Control Number: 51415

Item Number: 326

Addendum StartPage: 0

PUBLIC UTILITY COMMISSION OF TEXAS
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FILING CLERK

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR AUTHORITY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

WORKPAPERS TO THE

DIRECT TESTIMONY AND EXHIBITS OF JEFFRY C. POLLOCK

ON BEHALF OF
TEXAS INDUSTRIAL ENERGY CONSUMERS

April 1, 2021

326

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR AUTHORITY TO CHANGE RATES

DIRECT TESTIMONY OF

THOMAS P. BRICE

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

OCTOBER 2020

hundreds of downed power lines. Storm restoration efforts extended well into September. The Company requests authorization to charge the Texas jurisdictional Hurricane Laura restoration costs against the self-insurance reserve as a regulatory asset that will be reduced each month by the amount of reserve collected.

VIII. DEFERRAL OF CHANGES IN WHOLESALE TRANSMISSION CHARGES

Q. DOES SWEPCO'S COST OF SERVICE INCLUDE THE TRANSMISSION CHARGES INCURRED DURING THE TEST YEAR PURSUANT TO THE FERC-APPROVED SPP OATT?

A. Yes. SWEPCO is charged by SPP for the use of other SPP transmission owners' facilities to serve SWEPCO's customers. SWEPCO also receives payment from SPP for SPP members' use of SWEPCO's transmission facilities. These payments and receipts occur pursuant to FERC-approved tariffs and rates. The net amount that SWEPCO incurred during the Test Year is included in SWEPCO's requested cost of service in this proceeding.

Q. IS THIS NET AMOUNT INCURRED DURING THE TEST YEAR REPRESENTATIVE OF THE AMOUNT OF SUCH CHARGES SWEPCO WILL INCUR GOING FORWARD?

A. No. The costs historically incurred by SWEPCO under the SPP OATT will be outdated when the rates established in this proceeding take effect.

Q. DOES SWEPCO HAVE A PROPOSAL TO ADDRESS THE FACT THAT THE HISTORICALLY INCURRED SPP OATT COSTS ARE NOT REPRESENTATIVE OF THE COSTS SWEPCO WILL INCUR GOING FORWARD?

A. Yes. SWEPCO proposes that the portion of its ongoing SPP OATT charges that is above or below the net Test Year level approved for recovery by the Commission, be deferred into a regulatory asset or liability until they can be addressed in a future Transmission Cost Recovery Factor (TCRF) or base-rate proceeding. This proposal is discussed further in the direct testimony of SWEPCO witness John Aaron.

Q. DOES SWEPCO'S PROPOSAL HAVE SUPPORT IN PURA AND COMMISSION PRECEDENT?

A. Yes. Section 36.209 of PURA gives the Commission authority to allow a utility to recover "changes in wholesale transmission charges to the electric utility under a tariff approved by a federal regulatory authority" to the extent the charges have not otherwise been recovered. SWEPCO's proposal will allow recovery of the changes in transmission charges incurred by SWEPCO under the SPP OATT that the Commission has found reasonable and necessary as a matter of law. In fact, in Docket No. 42448, a SWEPCO TCRF proceeding, the Commission found that proof that the SPP charges were billed to and paid by SWEPCO pursuant to the SPP OATT demonstrates the reasonableness of the charges for retail ratemaking purposes as a matter of law.[2]

Q. DOES THE COMMISSION ALLOW ERCOT UTILITIES TO RECOVER CHANGES IN THEIR WHOLESALE TRANSMISSION CHARGES?

A. Yes. It is my understanding that the TCRF rule for distribution service providers operating in ERCOT (16 TAC § 25.193) authorizes the distribution service provider to

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[2] *Application of Southwestern Electric Power Company for Approval of Transmission Cost Recovery Factor*, Docket No. 42448, Final Order at Conclusion of Law No. 18 (Nov. 24, 2014).

charge or credit its customers for the amount of Commission-approved wholesale transmission cost changes to the extent that such costs vary from the transmission service cost used to fix the base rates of the distribution service provider. While amending this rule in Project No. 37909, the Commission observed that this recovery mechanism is appropriate because the ERCOT distribution service providers have no ability to avoid such costs or address and manage the regulatory lag that exists with respect to these costs. SWEPCO is in the same position regarding the costs it incurs under the SPP OATT. As such, SWEPCO is proposing to better match the costs SWEPCO incurs under the SPP OATT with the revenues received by the customers that ultimately benefit from the utilization of the open-access transmission system, similar to the recovery mechanism utilized by the ERCOT distribution service providers today.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR AUTHORITY TO CHANGE RATES

DIRECT TESTIMONY OF

JOHN O. AARON

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

OCTOBER 2020

"ALLOC" is defined in 16 TAC § 25.239(e) as "the utility's Texas retail allocation of transmission revenue requirements, as established in the utility's most recent base rate case." Based on SWEPCO's filing in this case, the jurisdictional allocation factors are applied against the various elements of the RR calculation to arrive at the Texas Jurisdictional values set forth in Column (C) of EXHIBIT JOA-5.

Q. HAVE YOU PREPARED AN EXHIBIT THAT SETS FORTH THE BASELINE AMOUNTS THAT WOULD BE USED TO SUBSEQUENTLY CALCULATE THE COMPONENTS OF THE TCRF REVENUE REQUIREMENT BASED ON SWEPCO'S FILING IN THIS CASE?

A. Yes. EXHIBIT JOA-5, Page 1, sets forth SWEPCO's TCRF revenue requirement baseline calculation. Column (D) provides the baseline amounts for the elements that will be used to compute the RR using the corresponding values from SWEPCO's filing in this case. These baseline values are from the cost allocation schedules I sponsor. EXHIBIT JOA-5, Page 2, contains the jurisdictional allocation factors used to calculate the TCRF baseline value and the TCRF class allocation factors.

<u>B. Request to Defer Ongoing ATC Expenses</u>

Q. ARE THE TEST YEAR ATC CHARGES INCLUDED IN SWEPCO'S PROPOSED TCRF BASELINE REPRESENTATIVE OF THE ONGOING LEVEL OF SUCH EXPENSES UNDER THE SPP OATT?

A. No, the Test Year ATC charges used in calculating the TCRF baseline revenue requirement, as described above, will be outdated from the day rates in this case become effective.

Q. WHAT IS THE RESULT IF THE ONGOING SPP CHARGES INCREASE OR DECREASE FROM THAT IN THE ATC COMPONENT USED TO CALCULATE THE TCRF BASELINE?

A. If the SPP charges billed to SWEPCO increase above the amount included in the Test Year ATC component of the TCRF baseline, then SWEPCO would under-recover the difference. Conversely, if the SPP charges billed to SWEPCO decrease below the amount included in the Test Year ATC, then SWEPCO would over-recover the difference.

Q. DOES SWEPCO HAVE A PROPOSAL TO ADDRESS THIS POSSIBILITY?

A. Yes. SWEPCO proposes that the portion of its ongoing SPP charges that qualify as ATC under 16 TAC § 25.239(b)(1) that is above or below the net ATC component of the baseline TCRF revenue requirement approved in this case be deferred into a regulatory asset or liability until they can be addressed in a future TCRF or base-rate proceeding.

Q. IS THE COMPANY'S PROPOSAL CONSISTENT WITH COMMISSION POLICY PURA § 36.209, AND 16 TAC § 25.239?

A. Yes. I am not an attorney, but it is my understanding that Commission policy has consistently considered expenses paid by SWEPCO under FERC-approved tariffs to be recoverable in the Company's retail rates. This policy is reflected in PURA § 36.209, and the Commission's TCRF rule, 16 TAC 25.239(b). Both the statute and the rule specify that the utility may recover changes in wholesale transmission charges under FERC tariffs, to the extent not otherwise recovered. Moreover, the Commission has found that SWEPCO is obligated to pay SPP the charges SPP bills to SWEPCO pursuant to the SPP OATT for the provision of transmission services to SWEPCO.[3]

VI. DISTRIBUTION COST RECOVERY FACTOR

Q. WHAT IS A DISTRIBUTION COST RECOVERY FACTOR OR DCRF?

A. A DCRF is a rate mechanism approved by the Texas Legislature that allows an electric utility to periodically adjust its rates for changes in certain distribution costs.

Q. HAS THE COMMISSION ADOPTED A RULE TO IMPLEMENT A DCRF?

A. Yes. The Commission has adopted 16 TAC § 25.243 to implement a DCRF as described by PURA § 36.210. The rule allows an electric utility not offering customer choice (e.g., SWEPCO) to file an application for a DCRF at any time other than the months of April and May.

Q. HAS SWEPCO IMPLEMENTED A DCRF?

A. Yes. SWEPCO had a DCRF baseline value approved in PUC Docket No. 48233 and implemented an update to its DCRF in PUC Docket No. 49041.

Q. WHAT RELIEF IS SWEPCO SEEKING IN THIS PROCEEDING WITH RESPECT TO THE ESTABLISHMENT OF THE DCRF?

A. In this proceeding, SWEPCO is resetting the DCRF baseline values for the components that are used for a subsequent implementation of the DCRF. Accordingly, with the approval and implementation of revised base rates reflecting SWEPCO's Test Year adjusted distribution costs, the DCRF rates will also be reset to zero.

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[3] *Application of Southwestern Electric Power Company for Approval of Transmission Cost Recovery Factor*, Docket No. 42448, Final Order at Conclusion of Law No. 16 (Nov. 24, 2014).

Southwestern Electric Power Company
TCRF Revenue Requirement Calculation
For the Test Year Ending March 31, 2020

Line No.	(A) Component	(B) Total Company	(C) Texas Retail Transmission Function	(D) Texas Retail Amount Included in SWEPCO Base Rate Order	(E) Net Change Not Included In Base Rate Order (C - D)
1	**TIC:**				
2	Transmission Plant in Service	$2,066,218,993	$904,072,262	$904,072,262	$0
3	Accumulated Depreciation	(570,785,047)	(249,746,484)	(249,746,484)	0
4	Net Plant in Service	$1,495,433,946	$654,325,778	$654,325,778	$0
5					
6	Accumulated Deferred Taxes	(208,942,255)	(91,422,496)	(91,422,496)	0
7					
8	**Total TIC**	$1,286,491,691	$562,903,283	$562,903,283	$0
9					
10	WACC	7 22%	7 22%	7 22%	
11					
12	**Return on TIC**	$92,935,304	$40,663,759	$40,663,759	$0
13					
14					
15					
16	**Investment-Related Expenses:**				
17	Depreciation Expense	$47,933,847	$20,973,412	$20,973,412	$0
18	Income Tax Expense - Note 1	34,779,087	16,544,686	16,544,686	0
19	Other Associated Taxes	67,742,851	6,447,554	6,447,554	0
20	Revenue Credits	(172,655,780)	(75,666,738)	(75,666,738)	0
21	**Total Investment-Related Expenses**	($22,199,994)	($31,701 086)	($31,701,086)	$0
22					
23	**Revreqt (line 12 + line 21)**	$70,735,310	$8,962,673	$8,962,673	$0
24					
25	**ATC:**				
26	SPP Charges and Fees	$157,881,876	$68,652,821	$68,652,821	$0
27	Non-SPP Charges	6,005,430	2,631,891	2,631,891	0
29	Other Transmission Charges	914,530	400,795	400,795	0
32	**Total ATC**	$164,801,836	$71,685,507	$71,685,507	$0
33					
34	**RR (line 23 + line 32)**	$235,537,145	$80,648,180	$80,648,180	$0

Note (1) Income Tax Expense is calculated for the Texas Retail Transmission Function

SOUTHWESTERN ELECTRIC POWER COMPANY
TCRF Allocation Factors
For the Test Year Ended March 31, 2020

Texas Jurisdictional Allocations Factors	TOTAL COMPANY	ARKANSAS RETAIL	LOUISIANA RETAIL	TEXAS RETAIL	FERC WHOLESALE
DEMPROD (4 CP Production Demand)	3,897	773	1 365	1,439	320
	100.0000%	19 8404%	35 0184%	36.9282%	8.2130%
DEMTRANS (SPP 12 CP)	3,112	625	1,123	1,364	-
	100 0000%	20 0757%	36 0991%	43 8252%	0.0000%
PLANT (Total Electric Plant In Service)	9,641,963,091	1,926,275,363	3,629,478,029	3,663,416,849	422,792,850
used in tax calc	100 0000%	19.9780%	37 6425%	37 9945%	4 3849%
DEPREXP (Depreciation Expense)	245,438,986	49,074,207	92,676,479	92,832,527	10,855,773
used in tax calc	100 0000%	19 9945%	37.7595%	37 8231%	4 4230%
TRANPLT	2,066,218,993	414,759,112	745,658,188	904,072,262	1,729,430
	100 0000%	20 0733%	36 0881%	43.7549%	0 0837%

	Total	Production	Transmission	Distribution
Texas Plant	3,663,416,849	1,880 853,036	915,798,742	866,765,071
used in tax calc		51 3415%	24 9985%	23.6600%

Class Allocation Factors (A&E 4CP)	
Residential	
Basic RS	36 56077%
Commercial	
General Service W/ Demand	3 87849%
General Service W/O Demand	1 24777%
Lighting & Power - Sec	27 27551%
Lighting & Power - Pri	5.67304%
Cotton Gin	0 03378%
Industrial	
Large Lighting & Power - Pri	1 66730%
Large Lighting & Power - Tran	15 37123%
Metal Melting - Sec	0.01468%
Metal Melting - Pri	0.26898%
Metal Melting - Tran	3 71612%
Oilfield - Pri	2 74553%
Oilfield - Sec	0 22068%
Municipal	
Municipal Pumping	0 44411%
Municipal Service	0 26664%
Lighting	
Municipal Lighting	0.19239%
Public Highway	0 00792%
Private/Area Lighting	0 36547%
Customer Owned Lighting	0 04960%
Total	100 00000%

§25.239. Transmission Cost Recovery Factor for Certain Electric Utilities.

(a) **Application.** The provisions of this section apply to an electric utility that operates solely outside of the Electric Reliability Council of Texas in areas of Texas included in the Southwest Power Pool or the Western Electricity Coordinating Council and that owns or operates transmission facilities.

(b) **Definitions.**

(1) **Approved transmission charges (ATC)** — Wholesale transmission charges approved by a federal regulatory authority that are not being recovered through the electric utility's other retail or wholesale rates and that are appropriately allocated to Texas retail customers. The charges may relate to the use of transmission facilities owned and operated by another transmission service provider or regional transmission organization, including transmission-related administrative fees but not including dispatch fees, congestion charges, costs incurred to hedge congestion charges, or ancillary service charges.

(2) **Transmission invested costs (TIC)** — The net change in the electric utility's transmission investment costs including additions, upgrades, and retirements as booked in FERC accounts 350-359, and accumulated depreciation.

(c) **Recovery authorized.** The commission, after notice and hearing, may allow an electric utility to recover its reasonable and necessary costs for transmission infrastructure improvement and changes in wholesale transmission charges to the electric utility under a tariff approved by a federal regulatory authority to the extent that the costs or charges have not otherwise been recovered and are incurred after December 31, 2005. Any such recovery shall be made through the use of a transmission cost recovery factor (TCRF) approved by an order of the commission. The TCRF shall be calculated pursuant to subsection (d) of this section. If a utility has not had a base rate case with a final order issued after December 2005, the utility shall not be eligible for recovery under this provision without first obtaining a final order in a base rate case.

(d) **Transmission cost recovery factor (TCRF).** The TCRF shall be determined by the following formula:

$$\text{TCRF} = \frac{RR * ClassALLOC}{BD}$$

Where:	TCRF = transmission cost recovery factor in dollars per unit, for billing each customer class.
	RR = transmission cost recovery factor revenue requirement, calculated pursuant to subsection (e) of this section.
	ClassALLOC = the customer class allocation factor used to allocate the transmission revenue requirement in the utility's most recent base rate case.
	BD = each customer class's annual billing determinant (kilowatt-hour, kilowatt, or kilovolt-ampere) for the previous calendar year.

(e) **Transmission cost recovery factor revenue requirement (RR).** For an electric utility subject to this section, the transmission cost recovery factor revenue requirement (RR) shall be calculated by using the following formula:

RR = [revreqt + ATC]*ALLOC	
Where:	Revreqt = the sum of the return on TIC, net of accumulated depreciation and associated accumulated deferred income taxes, plus investment-related expenses such as income taxes, other associated taxes, depreciation, and transmission–related miscellaneous revenue credits, but not including operation and maintenance expenses or administrative expenses. The return on TIC shall be calculated by multiplying the TIC by the utility's weighted-average cost of capital (WACC) as established for the utility in a final commission order in a base rate case, provided that the order was filed within three years prior to the initiation of the TCRF docket. Otherwise, a proxy WACC shall be used, with a cost of equity of 10%; and the capital structure and cost of debt as reported in the utility's most recent Earnings Monitoring Report filed pursuant to §25.73 of this title (relating to Financial and Operating Reports), adjusted for known and measurable changes.
	Transmission Invested Costs (TIC) is defined in subsection (b)(2) of this section.
	Approved Transmission Charges (ATC) is defined in subsection (b)(1) of this section.
	ALLOC = the utility's Texas retail allocation of transmission revenue requirements, as established in the utility's most recent base rate case.

(f) **Setting and amending the TCRF.** An electric utility that is subject to this section may file an application to set or amend a TCRF. The commission staff may also file an application to amend a TCRF. **An electric utility may not apply to amend its TCRF more frequently than once each calendar year, but a TCRF shall be reviewed or amended at least once every three years. Upon completion of a base rate case for a utility, the TCRF shall be set to zero.** In a docket in which the TCRF is reviewed or amended, the commission may order the refund of any previous over-recovery, but the commission shall not order the surcharge of any under-recovery. An over-recovery shall be considered to have occurred if the revenues from the TCRF were greater than the costs that the TCRF was intended to recover.

(g) **TCRF forms.** The commission may develop forms for TCRF applications and for monitoring the revenues from a TCRF. If the commission develops and approves such forms, an electric utility shall use the forms as required by the instructions accompanying the form.

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October 30, 2020

Ms. Ana Treviño
Public Utility Commission of Texas
Central Records
1701 N. Congress Avenue
Austin, Texas 78701

RE: PUC Docket No. 51415; *Application of Southwestern Electric Power Company for Authority to Change Rates*

Dear Ms. Treviño:

On October 14, 2020, Southwestern Electric Power Company (SWEPCO) filed a petition with the Public Utility Commission of Texas (Commission) seeking authority to change the company's base rates. SWEPCO submitted with its petition the Direct Testimony of John O. Aaron. The following workpapers supporting Mr. Aaron's testimony exhibits were inadvertently omitted from SWEPCO's filing:

- WP_EXHIBIT JOA-2 (Jurisdictional Production Allocation);
- WP_EXHIBIT JOA-3 (Jurisdictional Transmission Allocation);
- WP_EXHIBIT JOA-4 (Class Production and Class Allocations);
- WP_EXHIBIT JOA-5 (TCRF Calculation);
- WP_EXHIBIT JOA-6 (DCRF Calculation); and
- WP_EXHIBIT JOA-7 (GCRR Baseline Values).

Copies of these items have been electronically filed with this letter.

Respectfully submitted,

Patrick Pearsall

ATTORNEY FOR SOUTHWESTERN ELECTRIC POWER COMPANY

cc: All Parties of Record

Southwestern Electric Power Company
TCRF Revenue Requirement Calculation
For the Test Year Ending March 31, 2020

Line No.	(A) Component	(B) Total Company	(C) Texas Retail Transmission Function	(D) Texas Retail Amount Included in SWEPCO Base Rate Order	(E) Net Change Not Included In Base Rate Order (C - D)
1	TIC:				
2	Transmission Plant in Service	$2,066,218,993	$904,072,262	$904,072,262	$0
3	Accumulated Depreciation	(570,785,047)	(249,746,484)	(249,746,484)	0
4	Net Plant in Service	$1,495,433,946	$654,325,778	$654,325,778	$0
5					
6	Accumulated Deferred Taxes	(208,942,255)	(91,422,496)	(91,422,496)	0
7					
8	**Total TIC**	$1,286,491,691	$562,903,283	$562,903,283	$0
9					
10	WACC	7 22%	7 22%	7 22%	
11					
12	**Return on TIC**	$92,935,304	$40,663,759	$40,663,759	$0
13					
14					
15					
16	**Investment-Related Expenses:**				
17	Depreciation Expense	$47,933,847	$20,973,412	$20,973,412	$0
18	Income Tax Expense - Note 1	34,779,087	16,544,686	16,544,686	0
19	Other Associated Taxes	67,742,851	6,447,554	6,447,554	0
20	Revenue Credits	(172,655,780)	(75,666,738)	(75,666,738)	0
21	**Total Investment-Related Expenses**	($22,199,994)	($31,701,086)	($31,701,086)	$0
22					
23	**Revreqt (line 12 + line 21)**	$70,735,310	$8,962,673	$8,962,673	$0
24					
25	**ATC:**				
26	SPP Charges and Fees	$157,881,876	$68,652,821	$68,652,821	$0
27	Non-SPP Charges	6,005,430	2,631,891	2,631,891	0
29	Other Transmission Charges	914,530	400,795	400,795	0
32	**Total ATC**	$164,801,836	$71,685,507	$71,685,507	$0
33					
34	**RR (line 23 + line 32)**	$235,537,145	$80,648,180	$80,648,180	$0

Note (1) Income Tax Expense is calculated for the Texas Retail Transmission Function

PUC DOCKET NO. ______

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR APPROVAL TO AMEND TRANSMISSION COST RECOVERY FACTOR	§ § § §	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

SOUTHWESTERN ELECTRIC POWER COMPANY'S STATEMENT OF INTENT AND APPLICATION FOR APPROVAL TO AMEND TRANSMISSION COST RECOVERY FACTOR

DECEMBER 19, 2018

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*Electronic files provided on the attached flash drive and on the PUC Interchange - **2018 SWEPCO TCRF Pkg.pdf***

EXHIBIT JOA-2 (TCRF RR 2018).xlsx
EXHIBIT JOA-3 (SWEPCO 2018 Misc Rev).xlsx
EXHIBIT JOA-4 (TCRF Allocation and Factors).xlsx
Exhibit PKK-1 (TCRF Rev Requirement).xlsx
Exhibit PKK-3 TCRF Over-Under.xlsx
EXHIBIT WLS-1.xlsx
EXHIBIT WLS-2.xlsx
Smith WP - Additions by Project - WorkOrders.xlsx

Southwestern Electric Power Company
TCRF Revenue Requirement Calculation
For the Year Ending September 30, 2018

Line No.	(A) Component	(B) Transmission Total Company	(C) Texas Retail Transmission Function	(D) Texas Retail Trans Amount Included in SWEPCO Base Rates Docket No. 46449	(E) Net Change Not Included In Base Rate Order (C - D)
1	**TIC·**				
2	Transmission Plant in Service	$1,805,659,249	$710,197,756	$578,810,052	$131,387,704
3	Accumulated Depreciation	(547,978,331)	(215,395,573)	(196,049,290)	(19,346,283)
4	Net Plant in Service	$1,257,680,917	$494,802,182	$382,760,762	$112,041,420
5					
6	Accumulated Deferred Taxes	(274,882,178)	(108,048,945)	(88,349,265)	(19,699,680)
7					
8	**Total TIC**	$982,798,739	$386,753,237	$294,411,497	$92,341,740
9					
10	WACC	7 18%	7 18%	7 18%	
11					
12	**Return on TIC**	$70,541,559	$27,759,678	$21,131,739	$6,627,939
13					
14					
15					
16	**Investment-Related Expenses:**				
17	Depreciation Expense	$36,811,540	$14,469,647	$12,543,415	$1,926,232
18	Income Tax Expense - Note 1	11,206,626	4,693,856	3,548,358	1,145,498
19	Other Associated Taxes	63,652,682	5,063,129	3,745,805	1,317,324
20	Revenue Credits	(203,220,343)	(79,880,565)	(60,242,621)	(19,637,944)
21	**Total Investment-Related Expenses**	($91,549,495)	($55,653,933)	($40,405,043)	($15,248,890)
22					
23	**Revreqt (line 12 + line 21)**	($21,007,936)	($27,894,256)	($19,273,305)	($8,620,951)
24					
25	**ATC:**				
26	SPP Charges and Fees - Note 2	$200,961,524	$77,379,409	$56,214,726	$21,164,683
27	Wheeling Expense	513,035	171,035	161,208	9,827
28	Other Transmission Charges	1,068,854	420,138	394,452	25,687
29	**Total ATC**	$202,543,413	$77,970,583	$56,770,386	$21,200,197
30					
31	**RR (line 23 + line 29)**	$181,535,477	$50,076,327	$37,497,081	$12,579,246
32					
33	Settlement Adjustments	$0	$0	$0	$0
34					
35	Adjusted TCRF Revenue Requirement	$181,535,477	$50,076,327	$37,497,081	$12,579,246

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' SIXTH SET OF REQUESTS FOR INFORMATION

Question No. TIEC 6-11:

Please provide all workpapers in live EXCEL format showing how the monthly SPP load ratio shares were applied in determining the following amounts billed to SWEPCO for the period January 2019 through December 2020:
a. SPP-related revenues by service schedule as provided in SWEPCO Response No. TIEC 1-15a.
b. SPP-related expenses by service schedule as provided in SWEPCO Response No. TIEC 1-15b.

Response No. TIEC 6-11:

Please see TIEC 6-11 Attachment 1 for SPP AEP zone load data for 2019 and 2020. SPP-related revenues provided in SWEPCO Response No. TIEC 1-15a are assigned to the companies (SWEPCO and PSO) based on the Transmission Coordination Agreement and not load ratio shares. SPP-related expenses provided in SWEPCO Response No. TIEC 1-15b are allocated based on load ratio shares.

Prepared By: John O. Aaron Title: Dir Reg Pricing & Analysis

Sponsored By: John O. Aaron Title: Dir Reg Pricing & Analysis

Sponsored By: Michael A. Baird Title: Mng Dir Acctng Policy & Rsrch

AEP Companies PSO and SWEPCO
Network Load for January Through December 2019
Based on West Zone-SPP Monthly Transmission System Firm Peak Demands [1] for the Twelve Months Ended December 31, 2019

Historical Combined Load Worksheet

Unless noted (e g , PSO), the loads reported on lines 1 through 20 are the customer's schedule 9 and 11 loa

Line No		January	February	March	April	May	June	July	August	September	October	November	December			12 Month Average MW
	Peak Day	01/24/19	02/08/19	03/05/19	04/10/19	05/23/19	06/21/19	07/17/19	08/12/19	09/06/19	10/02/19	11/13/19	12/18/19			
	Peak Hour	800	800	800	1700	1700	1700	1700	1600	1700	1600	800	800			
	SPP Load Responsibility															
1	PSO	2561	2792	2805	2574	2970	3724	3923	4089	3731	3527	2569	2599	3155 333		3155
2	SWEPCO	2997	2891	2972	2449	3052	3362	3457	3664	3474	3301	2932	2839	3115 833		3116
3	AECC	622	673	661	375	536	629	663	705	635	602	615	614	610 833		611
4	AECC-MISO	143	150	149	113	161	176	177	185	183	157	125	138	154 750		155
5	WFEC	40	40	43	27	33	39	39	43	40	30	37	41	37 667		38
6	OMPA	76	85	86	78	92	138	147	156	140	125	79	81	106 917		107
7	OG&E ATOKA COALGATE	5	5	5	0	2	0	9	9	9	5	8	1	4 833		5
8	OG&E LINN	24	22	23	23	26	26	24	26	23	24	22	24	23 917		24
9	OG&E - TALL BEAR	14	10	12	13	13	14	13	12	13	13	13	13	12 760		13
10	ETEC	988	951	1055	514	701	822	868	933	890	798	1050	996	880 500		881
11	GREENBELT	7	8	6	5	4	7	17	17	13	5	7	7	8 583		9
12	LIGHTHOUSE	1	4	1	3	3	2	6	4	3	4	4	4	3 250		3
13	BENTONVILLE, AR	108	116	115	96	127	143	153	162	145	134	105	106	125 833		126
14	PRESCOTT, AR (ENTERGY)	11	9	12	10	13	12	14	16	13	12	9	10	11 750		12
15	MINDEN, LA (ENTERGY)	22	20	21	21	30	32	33	36	34	34	21	21	27 083		27
16	HOPE, AR	43	42	42	39	49	52	53	53	49	49	35	35	45 077		45
17	COFFEYVILLE, KS	104	103	105	104	106	100	117	116	113	113	104	41	102 167		102
18	SWEPCO - VALLEY	157	138	153	85	115	119	136	141	137	125	157	152	134 583		135
19	AECI	38	43	45	22	31	44	47	50	45	37	38	38	39 830		40
20	**System Firm Peak Demands**	**7961**	**8102**	**8311**	**6551**	**8064**	**9441**	**9896**	**10417**	**9690**	**9095**	**7930**	**7760**	**8601 500**	Sched - 9 12CP	**8602**
	Supporting Data															
21	PSO — PSO Native Load (a)	2574	2805	2817	2588	2987	3735	3937	4102	3742	3541	2582	2613			
	100% PSO E&W included in PSO native loac	-7	-7	-7	-6	-7	-6	-7	-7	-7	-6	-7	-7			
22	Allen Holdenville	-6	-6	-5	-8	-10	-5	-7	-6	-4	-8	-5	-7			
23	**PSO OATT Load Responsibility (includes LASOR rounding)**	**2561**	**2792**	**2805**	**2574**	**2970**	**3724**	**3923**	**4089**	**3731**	**3527**	**2569**	**2599**	3155 333		3155
	SWEPCO															
24	SWEPCO Native Load	3135	3015	3133	2439	3102	3431	3545	3767	3578	3392	3102	2984			
25	Eastman Load added October 2018	157	157	152	149	152	155	150	148	143	132	135	142			
26	VALLEY	-157	-138	-153	-85	-115	-119	-136	-141	-137	-125	-157	-152			
27	Rayburn	-138	-143	-160	-54	-87	-105	-102	-110	-110	-98	-148	-135			
28	**SWEPCO OATT Load Responsibility (incl LASOR rounding)**	**2997**	**2891**	**2972**	**2449**	**3052**	**3362**	**3457**	**3664**	**3474**	**3301**	**2932**	**2839**	3115 833		3116
29	**NTEC,TEXLA went under a combined TSR with ETEC in November 2016**														pr yr Sched - 11 12CP	**8602**
30	**OGE LINN went effective March 2019**															
	AEP Schedule 11 Worksheet															
31	PSO OATT Sched 9 load, Ln 1	2561	2792	2805	2574	2970	3724	3923	4089	3731	3527	2569	2599	3155 333		3155
32	less GRDA load on PSO Jan-Nov(b) 2015 no longer used	0	0	0	0	0	0	0	0	0	0	0	0	0 000		0
33	WFEC load already subtracted from PSO schedule 9 load	0	0	0	0	0	0	0	0	0	0	0	0	0 000		0
34	Subtotal PSO Schedule 11 load	2561	2792	2805	2574	2970	3724	3923	4089	3731	3527	2569	2599	3155 333		3155
35	SWEPCO Sched 11 load, Ln 2	2997	2891	2972	2449	3052	3362	3457	3664	3474	3301	2932	2839	3115 833		3116
36	TOTAL AEP Affiliate Schedule 11 Load	5558	5683	5777	5023	6022	7086	7380	7753	7205	6828	5501	5438	6271 167		6271
37	TOTAL AEP ZONAL SCHEDULE 11	7961	8102	8311	6551	8064	9441	9896	10417	9690	9095	7930	7760	8601 510		8602

NOTEs

[a] PSO Native load includes PSO load on GRDA

[b] GRDA and PSO enjoy a grandfathered load swap arrangement Historically, both PSO load on GRDA and GRDA load on PSO were included in the PSO OATT load responsibility (Schedule 9) Beginning in Dec 2015, loads are telemetered - AEP and GRDA mutually agreed to report only their own load telemetered from the other zone for purposes of both Sch 9 & 11 Therefore, for Dec 2015 and forward, PSO will only report PSO load on GRDA for both Sch 9 & 11 reporting purposes as agreed to with GRDA Also, for Schedule 11 purposes, in agreement w/SPP & GRDA, PSO will report the PSO load on GRDA in Schedule 11 while GRDA will report its load on PSO in its Schedule 11 values for the entire year

{c} OG&E Atoka and Coalgate merged under 1 TSR (OG&E LSE) beginning with September 2018 billing SPP required the merged loads to be reported for Jan - Dec 2018

AEP Companies: PSO and SWEPCO
Network Load for January Through December 2020
Based on West Zone-SPP Monthly Transmission System Firm Peak Demands [1] for the Twelve Months Ended December 31, 2020

Historical Combined Load Worksheet

Unless noted (e g , PSO), the loads reported on lines 1 through 20 are the customer's schedule 9 and 11 loa

Line No		January	February	March	April	May	June	July	August	September	October	November	December		12 Month Average MW
	Peak Day	01/21/20	02/27/20	03/26/20	04/08/20	05/04/20	06/05/20	07/14/20	08/10/20	09/08/20	10/11/20	11/30/20	12/17/20		
	Peak Hour	800	800	1700	1800	1700	1700	1700	1600	1600	1700	900	800		
	SPP Load Responsibility														
1	PSO	2580	2548	2505	2636	2911	3504	3724	3873	3349	2789	2382	2513	2942 833	2943
2	SWEPCO	2664	2798	2422	2569	2602	3182	3391	3459	3173	2561	2357	2731	2825 750	2826
3	AECC	614	586	402	490	439	646	655	704	606	503	514	594	562 750	563
4	AECC-MISO	139	129	108	125	112	169	161	185	162	130	125	140	140 417	140
5	WFEC	40	42	29	32	24	32	42	39	36	34	37	41	35 667	36
6	OMPA	76	77	85	82	117	131	147	141	111	98	74	78	101 417	101
7	OG&E ATOKA COALGATE	4	5	1	2	5	4	9	5	9	8	9	9	5 833	6
8	OG&E LINN	23	23	21	16	15	22	22	20	19	20	22	21	20 333	20
9	OG&E - TALL BEAR	12	13	14	13	12	13	13	13	13	14	14	13	13 083	13
10	ETEC	973	991	585	650	688	820	893	905	758	713	763	988	810 583	811
11	GREENBELT	6	5	4	7	7	12	18	16	6	7	6	8	8 500	9
12	LIGHTHOUSE	2	3	1	2	2	4	6	5	2	1	3	1	2 667	3
13	BENTONVILLE, AR	109	104	87	102	92	143	138	152	136	107	95	99	113 667	114
14	PRESCOTT, AR (ENTERGY)	11	10	10	7	13	12	15	12	14	11	9	8	11 000	11
15	MINDEN LA (ENTERGY)	20	19	19	21	23	29	33	34	30	21	16	19	23 667	24
16	HOPE, AR	35	34	30	32	36	42	47	48	44	30	31	34	36 917	37
17	COFFEYVILLE, KS	106	103	26	97	80	99	111	112	114	96	100	105	95 750	96
18	SWEPCO - VALLEY	145	146	97	94	106	132	139	136	116	78	109	143	120 083	120
19	AECI	41	34	25	31	28	46	46	43	41	32	30	39	36 333	36
20	**System Firm Peak Demands**	7600	7670	6471	7008	7312	9042	9610	9902	8739	7253	6696	7584	7907 25 Sched - 9 12CP	7907
	Supporting Data														
21	PSO — PSO Native Load (a)	2591	2561	2517	2649	2922	3515	3737	3884	3360	2801	2394	2525		
	100% PSO E&W included in PSO native loac	-6	-6	-7	-7	-6	-7	-6	-6	-6	-7	-7	-7		
22	Allen Holdenville	-5	-7	-5	-6	-5	-5	-7	-5	-5	-6	-5	-5		
23	PSO OATT Load Responsibility (includes LASOR rounding)	2580	2548	2505	2636	2911	3503	3724	3873	3349	2788	2381	2513	2942 583	2943
	SWEPCO														
24	SWEPCO Native Load	2664	2798	2422	2569	2598	3182	3391	3459	3173	2561	2357	2731		
25	Eastman Load added October 2018	136	157	158	158	153	153	151	156	160	1	152	153		
26	VALLEY	-145	-146	-97	-94	-106	-132	-139	-136	-116	-78	-109	-143		
27	Rayburn	0	0	0	0	0	0	0	0	0	0	0	0		
28	SWEPCO OATT Load Responsibility (incl LASOR rounding)	2655	2809	2483	2633	2645	3203	3403	3479	3217	2484	2400	2741	2846 028	2846
		7738	7813	6631	7062	7399	9147	9712	10012	8849	7351	6844	7719		
29	NTEC,TEXLA went under a combined TSR with ETEC in November 2016													pr yr Sched - 11 12CP	**7907**
30	OGE LINN went effective March 2019														
	AEP Schedule 11 Worksheet														
31	PSO OATT Sched 9 load, Ln 1	2580	2548	2505	2636	2911	3504	3724	3873	3349	2789	2382	2513	2942 833	2943
32	less GRDA load on PSO Jan-Nov(b) 2015 no longer used	0	0	0	0	0	0	0	0	0	0	0	0	0 000	0
33	WFEC load already subtracted from PSO schedule 9 load	0	0	0	0	0	0	0	0	0	0	0	0	0 000	0
34	Subtotal PSO Schedule 11 load	2580	2548	2505	2636	2911	3504	3724	3873	3349	2789	2382	2513	2942 833	2943
35	SWEPCO Sched 11 load, Ln 2	2664	2798	2422	2569	2602	3182	3391	3459	3173	2561	2357	2731	2825 750	2826
36	TOTAL AEP Affiliate Schedule 11 Load	5244	5346	4927	5205	5513	6686	7115	7332	6522	5350	4739	5244	5768 583	5769
37	TOTAL AEP ZONAL SCHEDULE 11	7600	7670	6471	7008	7312	9042	9610	9902	8739	7253	6696	7584	7907 250	7907

NOTEs

[a] PSO Native load includes PSO load on GRDA

[b] GRDA and PSO enjoy a grandfathered load swap arrangement Historically, both PSO load on GRDA and GRDA load on PSO were included in the PSO OATT load responsibility (Schedule 9) Beginning in Dec 2015, loads are telemetered - AEP and GRDA mutually agreed to report only their own load telemetered from the other zone for purposes of both Sch 9 & 11 Therefore, for Dec 2015 and forward, PSO will only report PSO load on GRDA for both Sch 9 & 11 reporting purposes as agreed to with GRDA Also, for Schedule 11 purposes, in agreement w/SPP & GRDA, PSO will report the PSO load on GRDA in Schedule 11 while GRDA will report its load on PSO in its Schedule 11 values for the entire year

(c) OG&E Atoka and Coalgate merged under 1 TSR (OG&E LSE) beginning with September 2018 billing SPP required the merged loads to be reported for Jan - Dec 2018

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SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' FIFTH SET OF REQUESTS FOR INFORMATION

Question No. TIEC 5-1:

Please provide the dollar impact on SWEPCO's revenue requirement in this case of including versus excluding retail behind-the-meter generation in the monthly peak load that SWEPCO reports to SPP.

Response No. TIEC 5-1:

The estimated dollar impact on SWEPCO's revenue requirement is $5.7 million which reflects and is based on billing from SPP.

Prepared By: Earlyne T. Reynolds	Title: Reg Pricing & Analysis Mgr
Sponsored By: Jennifer L. Jackson	Title: Reg Pricing & Analysis Mgr
Sponsored By: John O. Aaron	Title: Dir Reg Pricing & Analysis

SCHEDULE 11
BASE PLAN ZONAL CHARGE AND REGION-WIDE CHARGE

I. Introduction

Except as provided herein, pursuant to Part V of this Tariff, Base Plan Zonal Charges and Region-wide Charges shall be assessed to Network Customers and, where applicable, Transmission Owners based on Resident Load. Likewise, Base Plan Zonal Charges and the Region-wide Charge shall be assessed to each Transmission Customer taking Point-To-Point Transmission Service under the Tariff based on Reserved Capacity. These charges will be applied only to service taken in whole or in part within the Eastern Interconnection. Western-UGP shall be exempt from the Region-wide Charge under this Schedule 11 in accordance with Section 39.3(e) of this Tariff. For the purpose of determining the Region-wide Load Ratio Shares for application of Schedule 11, transmission of Federal Power-Western-UGP to the Statutory Load Obligations served by Western-UGP shall be excluded from the Transmission Provider's monthly Zone transmission load for Zone 19 used as a component of the divisor for all Zones and from the numerator used for Zone 19. The charges stated in Schedule 11 shall not be changed absent a filing with the Commission.

II. Base Plan Zonal Charges and Region-wide Charge to Resident Load

A. Calculation of Annual Transmission Revenue Requirement

In calculating the Base Plan Zonal Annual Transmission Revenue Requirements and Region-wide Annual Transmission Revenue Requirement, the Transmission Provider shall sum the applicable, Commission-approved annual transmission revenue requirements for upgrades eligible for cost recovery under this Schedule 11, as allocated in accordance with Attachment J of this Tariff. Subject to the limitations in subsections 1 and 2 below, such annual transmission revenue requirements shall be reduced by the previous calendar year's amount of (i) point-to-point revenue received by each Transmission Owner resulting from charges under Section III of this Schedule 11 and (ii) revenue distributed to each Transmission Owner under Section IV of Attachment AU and allocated in proportion to Point-To-Point Transmission Service Schedule 11 revenue under Section V of Attachment AU. Any such adjustment for the previous calendar year point-to-point revenue shall be set forth in the RRR File.

1. For each Transmission Owner utilizing a formula rate, the Transmission Provider shall not make an adjustment of the Transmission Owner's annual transmission revenue requirements under this Section II.A if point-to-point revenue resulting from charges under Section III of this Schedule 11 and revenue distributed and allocated under Attachment AU is credited and updated on an annual basis in the Transmission Owner's formula rate in a manner that reduces the annual transmission revenue requirements for upgrades eligible for cost recovery under this Schedule 11.
2. For each Transmission Owner utilizing a stated rate or utilizing a formula rate without annual update of the Schedule 11 revenue credits, the revenue adjustment described in this Section II.A shall be only the difference, whether positive or negative, between the previous calendar year Point-To-Point Transmission Service Schedule 11 revenue and the amount of point-to-point revenue and revenue distributed and allocated under Attachment AU, if any, already credited in the calculation of the Transmission Owner's annual transmission revenue requirements included in the Base Plan Zonal Annual Transmission Revenue Requirements and Region-wide Annual Transmission Revenue Requirement. The amount of revenue resulting from charges under Section III of this Schedule 11 and revenue distributed and allocated under Attachment AU that is already credited in the calculation of the Transmission Owner's annual transmission revenue requirements included in the Base Plan Zonal Annual Transmission Revenue Requirements and Region-wide Annual Transmission Revenue Requirement is shown in Table 3, Section 1 of Attachment H.

B. Base Plan Zonal Charge to Resident Load

The Network Customer and the Transmission Owner shall pay a monthly Base Plan Zonal Charge, which shall be determined by multiplying its Base Plan Zonal Load Ratio Share by one twelfth (1/12) of the Base Plan Zonal Annual Transmission Revenue Requirement specified in Attachment H less any amount reallocated in accordance with Section IV.A of Attachment J for each Zone in which the Network Customer's or

Transmission Owner's Resident Load is physically located. Where a Network Customer has designated Network Load not physically interconnected with the Transmission System under Section 31.3, Network Customer shall pay a monthly Zonal Base Plan Charge, which shall be determined by multiplying its Base Plan Zonal Load Ratio Share by one twelfth (1/12) of the Base Plan Zonal Annual Transmission Revenue Requirement specified in Attachment H less any amount reallocated in accordance with Section IV.A of Attachment J for the Zone that is the basis for charges under Schedule 11.

1. Determination of Network Customer's and Transmission Owner's Monthly Zonal Resident Load

The Network Customer's or Transmission Owner's monthly zonal Resident Load is its integrated hourly load coincident with the monthly peak of the Zone where the Resident Load is physically located. Where a Network Customer or Transmission Owner has Resident Load in more than one Zone, the monthly Resident Load will be determined separately for each Zone. Where a Network Customer has designated Network Load not physically interconnected with the Transmission System under Section 31.3, the Network Customer's monthly Resident Load will be its hourly load coincident with the monthly peak of the Zone that is the basis for charges under Schedule 11.

2. Determination of Network Customer's and Transmission Owner's Monthly Zonal Resident Load for Zone 10

The Network Customer's or Transmission Owner's monthly zonal Resident Load shall be calculated in accordance with Section B.1 of this Schedule 11; except that the Network Customer's monthly zonal Resident Load shall be reduced by the Federal-Power Southwestern as identified in Section 34.9 of this Tariff.

3. Determination of Transmission Provider's Monthly Zone Transmission Load

The Transmission Provider's monthly Transmission System load shall be determined in accordance with Section 34.5 of this Tariff.

C. Region-wide Charge to Resident Load

Network Customers and Transmission Owners shall pay a monthly Region-wide Charge, which shall be determined as (i) the product of its Region-wide Load Ratio Share applicable to Section I, Table 2-A of Attachment H and one twelfth (1/12) of the Region-wide Annual Transmission Revenue Requirement specified in Section I, Table 2-A of Attachment H, plus (ii) the product of its Region-wide Load Ratio Share applicable to Section I, Table 2-B of Attachment H and one twelfth (1/12) of the Region-wide Annual Transmission Revenue Requirement specified in Section I, Table 2-B of Attachment H.

1. Determination of Network Customer's and Transmission Owner's Monthly Regional Resident Load in Zones 1 through 9 and 11 through 18

For Zones 1 through 9 and 11 through 18, the Network Customer's or Transmission Owner's monthly regional Resident Load is the sum of its monthly zonal Resident Load for each Zone, where the monthly zonal Resident Load is determined separately for each Zone coincident with the monthly peak of the Zone in accordance with Section II.B.1.

2. Determination of Network Customer's and Transmission Owner's Monthly Regional Load in Zone 19

For application of the Region-wide Charge under this Schedule 11, the Network Customer's or Transmission Owner's load for Zone 19 shall be the integrated hourly load coincident with the monthly peak of Zone 19 calculated in accordance with Section II.B.1 less: (i) load in the Western Interconnection to the extent that such load is served only by resources in the Western Interconnection, and (ii) service provided under the Western-UGP Federal Service Exemption.

3. Determination of Network Customer's and Transmission Owner's Monthly Regional Load in Zone 10

For application of the Region-wide Charge under this Schedule 11, the Network Customer's or Transmission Owner's load for Zone 10 shall be the integrated hourly load coincident with the monthly peak of Zone 10 calculated in accordance with Section II.B.2.

4. Determination of Transmission Provider's Monthly Regional Transmission System Load

The Transmission Provider's monthly regional Transmission System load is the sum of the monthly Zone transmission load for each Zone, where the monthly zone transmission load for each Zone is determined on a non-coincident basis in accordance with Section II.B.2, but with (a) Zone 19 load modified in accordance with Section II.C.2 and (b) Zone 10 load modified in accordance with Section II.C.3.

D. Special Provision for Non-Federal Service Exemption service to Western-UGP's Statutory Load Obligations

Western-UGP's Statutory Load Obligations ordinarily served by Federal Power Western-UGP, may be served on occasion from resources where the Western-UGP Federal Service Exemption from Schedule 11 Region-wide Charges is not applicable. In any such instance, Region-wide Charges will be applied as calculated pursuant to Sections III.C.1.a and III.C.3 of this Schedule 11.

III. Base Plan Zonal Charge and Region-wide Charge for Point-To-Point Transmission Service

A. Base Plan Zonal Charge for Point-To-Point Transmission Service

The Base Plan Zonal Charge shall be assessed to Transmission Customers taking Firm or Non-Firm Point-To-Point Transmission Service under the SPP Tariff. The Transmission Customer shall pay the Base Plan Zonal Rate (per kW of Reserved Capacity) based upon the Zone where the load is located for Point-To-Point Transmission Service where the generation source is outside the SPP Region and the load is located within the SPP Region and for Point-To-Point Transmission Service where both the generation source and the load are located within the SPP Region. For Point-To-Point Transmission Service where the generation source is located within the SPP Region and the load is located outside of the SPP Region, and for Point-To-Point Transmission Service where both the generation source and the load are located outside of the SPP Region, the Transmission Customer shall pay the Base Plan Average Zonal Rate (per kW of Reserved Capacity). The Base Plan Zonal Rates and the Base Plan Average Zonal Rate shall be calculated in accordance with Section III.D and set forth in the RRR File posted on the SPP website.

B. Region-wide Charge for Point-To-Point Transmission Service

The Region-wide Charge shall be assessed to Transmission Customers taking Firm or Non-Firm Point-To-Point Transmission Service under the SPP Tariff. The Transmission Customer shall pay the Region-wide Rate (per kW of Reserved Capacity) for Point-To-Point Transmission Service. The Region-wide Rate shall be calculated in accordance with Section III.C and set forth in the RRR File posted on the SPP website.

C. Region-wide Rate for Point-To-Point Transmission Service

1. Determination of Annual Region-wide Rate

a. The Region-wide Annual Transmission Revenue Requirement specified in Attachment H are the basis for the Region-wide Rate. Except for service where the load is located within Zone 19, the annual Region-wide Rate for Firm Point-To-Point Transmission Service shall be determined in accordance with the following formula:

RR = RATRR2A/MRTL 1 to 18 + RATRR2B/MRTL

in which

RR = the annual Region-wide Rate

RATRR2A = the Region-wide Annual Transmission Revenue Requirement specified in Table 2-A of Section I, Attachment H

RATRR2B = the Region-wide Annual Transmission Revenue Requirement specified in Table 2-B of Section I, Attachment H

MRTL 1 to 18 = the average of the monthly regional Transmission System loads in Zones 1 to 18 only, for the twelve months of the calendar year prior to the billing year. The monthly regional Transmission System load shall be determined in accordance with Section II.C.3 less the Zone 19 load modified in accordance with Section II.C.2.

MRTL = the average of the monthly regional Transmission System loads, for the twelve months of the calendar year prior to the billing year. The monthly regional Transmission System load is determined in accordance with Section II.C.3.

b. For service where the load is located within Zone 19, the annual Region-wide Rate for Firm Point-to-Point Transmission Service shall be determined in accordance with the following formula:

RR19= RATRR2B/MRTL

in which

RR19= the annual Region-wide Rate applicable to load in Zone 19

RATRR2B= as defined above

MRTL= as defined above

2. Region-wide Rate for Firm Point-To-Point Transmission Service

The Region-wide Rate for Firm Point-To-Point Transmission Service shall be:

Per month =	annual Region-wide Rate divided by 12;
Per week =	annual Region-wide Rate divided by 52;
Per day "on-peak" =	the "per week" Region-wide Rate divided by 5; provided that the rate for 5 to 7 consecutive days may not exceed the "per week" Region-wide Rate; and
Per day "off-peak" =	the "per week" Region-wide Rate divided by 7.

3. Region-wide Rate for Non-Firm Point-To-Point Transmission Service

The Region-wide Rate for Non-Firm Point-To-Point Transmission Service shall be:

Per month =	annual Region-wide Rate divided by 12;
Per week =	annual Region-wide Rate divided by 52:
Per day "on-peak" =	the "per month" Region-wide Rate multiplied by 12 then divided by 260;
Per day "off-peak" =	the "per month" Region-wide Rate multiplied by 12 then divided by 365;
Per hour "on-peak" =	the "per month" Region-wide Rate multiplied by 12 then divided by 4160; and
Per hour "off-peak" =	the "per month" Region-wide Rate multiplied by 12 then divided by 8760.

4. Total Region-wide Charge

The total Region-wide Charge paid by a Transmission Customer pursuant to a reservation for hourly delivery shall not exceed the above on-peak daily rate multiplied by the highest amount of Reserved Capacity in any hour during such day. The total Region-wide Charge in any week, pursuant to a reservation for hourly or daily delivery, shall not exceed the above Region-wide Rate specified for weekly delivery multiplied by the highest amount of Reserved Capacity in any hour during such week.

5. Rate Sheet for Region-wide Point-To-Point Transmission Service

Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth in the ("RRR File") posted on the SPP website.

Non-Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth in the RRR File.

D. Base Plan Zonal Rates for Point-To-Point Transmission Service

1. Determination of Annual Base Plan Zonal Rate

The Base Plan Zonal Annual Transmission Revenue Requirement specified in Attachment H less any amount reallocated in accordance with Section IV.A of Attachment J is the basis for the Base Plan Zonal Rates. The annual Base Plan Zonal Rates for Firm Point-To-Point Transmission Service shall be determined in accordance with the following formula for each Zone.

BPZR = BPZATRR/MZTL

in which

BPZR = the annual Base Plan Zonal Rate for the Zone

BPZATRR = the Base Plan Zonal Annual Transmission Revenue Requirement for the Zone as specified in Attachment H less any amount reallocated in accordance with Section IV.A of Attachment J

MZTL = the average of the sum of the monthly Zone transmission load for the Zone for the twelve months of the calendar year prior to the billing year. The monthly Zone transmission load is determined in accordance with Section II.B.2.

2. Base Plan Zonal Rate for Firm Point-To-Point Transmission Service

The Base Plan Zonal Rate for Firm Point-To-Point Transmission Service for each Zone shall be:

Per month =	annual Base Plan Zonal Rate for the Zone divided by 12;
Per week =	annual Base Plan Zonal Rate for the Zone divided by 52;
Per day "on-peak" =	the "per week" Base Plan Zonal Rate for the Zone divided by 5; provided that the rate for 5 to 7 consecutive days may not exceed the "per week" Base Plan Zonal Rate;
Per day "off-peak" =	the "per week" Base Plan Zonal Rate for the Zone divided by 7.

3. Base Plan Zonal Rate for Non-Firm Point-To-Point Transmission Service

The Base Plan Zonal Rate for Non-Firm Point-To-Point Transmission Service for each Zone shall be:

Per month =	annual Base Plan Zone Rate for the Zone divided by 12;
Per week =	annual Base Plan Zonal Rate for the Zone divided by 52:
Per day "on-peak" =	the "per month" Base Plan Zonal Rate for the Zone multiplied by 12 then divided by 260;
Per day "off-peak" =	the "per month" Base Plan Zonal Rate for the Zone multiplied by 12 then divided by 365;
Per hour "on-peak" =	the "per month" Base Plan Zonal Rate for the Zone multiplied by 12 then divided by 4160; and
Per hour "off-peak" =	the "per month" Base Plan Zonal Rate for the Zone multiplied by 12 then divided by 8760.

4. Base Plan Average Zonal Rate

The total Base Plan Zonal Annual Transmission Revenue Requirement specified in Attachment H for all Zones less the total of all zonal amounts reallocated in accordance with Section IV.A of Attachment J is the basis for the Base Plan Average Zonal Rate. The annual Base Plan Average Zonal Rate for Firm Point-To-Point Transmission Service shall be determined in accordance with the following formula.

BPAZR = TBPZATRR/MRTL

in which

BPAZR = the annual Base Plan Average Zonal Rate

TBPZATRR = the total Base Plan Zonal Annual Transmission Revenue Requirement for all Zones as specified in Attachment H less the total of all zonal amounts reallocated in accordance with Section IV.A of Attachment J

MRTL = as defined in Section III.C.1

The Base Plan Average Zonal Rates for Firm Point-To-Point Transmission Service and Non-Firm Point-To-Point Transmission Service for each month, week, day on-peak, day off-peak, hour on-peak, and hour off-peak shall be based on the annual Base Plan Average Zonal Rate and calculated consistently with the formulas shown in Sections III.D.2 and III.D.3.

5. Total Zonal Base Plan Charge

The total zonal charge paid by a Transmission Customer under this Schedule 11 pursuant to a reservation for hourly delivery shall not exceed the applicable on-peak daily rate multiplied by the highest amount of Reserved Capacity in any hour during such day. The total zonal charge under this Schedule 11 in any week, pursuant to a reservation for hourly or daily delivery, shall not exceed the applicable rate specified for weekly delivery multiplied by the highest amount of Reserved Capacity in any hour during such week.

6. Rate Sheets for Base Plan Zonal Point-To-Point Transmission Service

Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth in the RRR File posted on the SPP website.

Non-Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth in the RRR File posted on the SPP website.

E. On-Peak and Off-Peak

Off-Peak days shall be Saturdays and Sundays and all NERC holidays. All other days shall be On-Peak. All hours during Off-Peak days shall be Off-Peak. On-Peak hours during On-Peak days shall be all hours from HE 0700 through HE 2200 Central Prevailing Time. All other hours during On-Peak days shall be Off-Peak.

Reserved for Future Use

Reserved for Future Use

B - Definitions

Balanced Portfolio: A set of transmission upgrades that provides economic benefits across the SPP Region that meet the requirements in Sections IV.3 and IV.4 of Attachment O.

Balanced Portfolio Region-wide Annual Transmission Revenue Requirement: The annual transmission revenue requirement for an approved Balanced Portfolio determined in accordance with Attachment J to this Tariff.

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time in order to:

(1) Match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) Maintain scheduled interchange with other Balancing Authority Areas, within the limits of Good Utility Practice;

(3) Maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) Provide for sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Balancing Authority Area: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

Base Plan Region-wide Annual Transmission Revenue Requirement: The sum of the annual transmission revenue requirement for each Base Plan Upgrade and of the Accredited Revenue Requirement(s), if any, that are allocated to the SPP Region in accordance with Attachment J to this Tariff.

Base Plan Upgrades: Those upgrades included in and constructed pursuant to the SPP Transmission Expansion Plan in order to ensure the reliability of the Transmission System. Base Plan Upgrades shall also include: (i) those Service Upgrades required for new or changed Designated Resources to the extent allowed for in Attachment J to this Tariff, (ii) ITP Upgrades that are approved for construction by the SPP Board of Directors, (iii) high priority upgrades, excluding Balanced Portfolios, that are approved for construction by the SPP Board of Directors, and (iv) Network Upgrades due to the retirement of a Resource in accordance with Attachment AB to this Tariff. For Zones 1 through 15, all such upgrades shall specifically exclude planned Transmission System facilities identified in the SPP Transmission Expansion Plan that are: (i) placed in service during the 2005 calendar year or (ii) required to be in service to meet the SPP Criteria and the NERC Reliability Standards for the summer of 2005. For Zones 16, 17, and 18, all such upgrades shall specifically exclude planned Transmission System facilities in those zones identified in the SPP Transmission Expansion Plan Report (2009 – 2018) that are required to be in service to meet the SPP Criteria and the NERC Reliability Standards for the summer of 2008 or which are in operation prior to January 1, 2009, except for those upgrades that are in service prior to January 1, 2009 and are components of Phase 1 of the NPPD 345kV Norfolk to Lincoln (ETR) project or OPPD Sub 1255/3455 Transformer project. Network Upgrades that are components of Phase 1 of the NPPD 345kV Norfolk to Lincoln (ETR) project or OPPD Sub 1255/3455 Transformer project that are in service prior to January 1, 2009 will be Base Plan Upgrades, however, the Zonal component of the costs shall be 100% allocated to the respective host zone. The Base Plan Upgrades in Zones 1 through 18 identified by the Transmission Provider with a need date prior to October 1, 2015 shall not be allocable to Zone 19. The upgrades in Zone 19 identified by the Transmission Provider with a need date prior to October 1, 2015, shall not constitute Base Plan Upgrades. The facilities identified in Schedule 2 to Attachment J are expressly deemed to be Base Plan Upgrades pursuant to Attachment J, Section III.A.2.

Base Plan Zonal Annual Transmission Revenue Requirement: For each Zone, the sum of the annual transmission revenue requirement for each Base Plan Upgrade and of the Accredited Revenue Requirement(s), if any, that are allocated to the Zone in accordance with Attachments J and S to this Tariff.

Base Plan Zonal Charge: Zonal component of the charge assessed by the Transmission Provider in accordance with Schedule 11 to recover the revenue requirement of facilities classified as Base Plan Upgrades.

Base Plan Zonal Load Ratio Share: Ratio of a Network Customer's or Transmission Owner's Resident Load in a Zone to the total load in that Zone computed in accordance with Section II.B to Schedule 11 of this Tariff and calculated on a calendar year basis, for the prior calendar year. Customer loads used to determine the Base Plan Zonal Load Ratio Share shall be adjusted for real power losses in accordance with the provisions set out in Section 28.5 of this Tariff.

Base Plan Zonal Rate: Zonal component of the rate (per kW of Reserved Capacity for Point-To-Point Transmission Service) assessed by the Transmission Provider in accordance with Schedule 11 to recover the revenue requirement of facilities classified as Base Plan Upgrades.

Business Day: A day on which the Federal Reserve System is open for business.

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' FIFTH SET OF REQUESTS FOR INFORMATION

Question No. TIEC 5-3:

Please indicate how many MW or kW of load would be included in SWEPCO's reporting of monthly peak load data to SPP in each of the following circumstances:

a. an interruptible customer that uses 50 MW of power during most hours of the month but is not consuming power at the time of the monthly peak of the SWEPCO zone.
b. a firm customer whose load varies over the course of the month between 10 MW and 50 MW, but that is only consuming 10 MW at the time of monthly peak of the SWEPCO zone.
c. a backup customer that self-supplies 50 MW of its own load with behind-the-meter generation throughout the month and does not take any backup or other power from SWEPCO during the month.
d. a customer that has 50 MW of load supplied by behind-the-meter generation, which load is integrated with the generation so that the customer will never take more than 10 MW of backup or standby power from SWEPCO, and which is not taking any power from SWEPCO at the time of the monthly peak of the SWEPCO zone.
e. a residential or commercial solar customer that is generating 10 kW of its 20 kW load at the time of the monthly peak of SWEPCO zone.

Response No. TIEC 5-3:

a. 0 MW for this customer.
b. 10 MW for this customer.
c. 50 MW if the behind the meter generator was serving that load at the time of the peak.
d. 50 MW if the behind the meter generator was serving that load at the time of the peak.
e. 10 kW because SWEPCO has not made any adjustments for such loads in its reporting to SPP at this time.

Prepared By: C. Richard Ross	Title: Dir Transmission RTO Policy
Prepared By: Chad M. Burnett	Title: Dir Economic Forecasting
Sponsored By: Chad M. Burnett	Title: Dir Economic Forecasting

34.4 Determination of Network Customer's Monthly Network Load:

The Network Customer's monthly Network Load is its hourly load (60 minute, clock-hour); provided, however, the Network Customer's monthly Network Load will be its hourly load coincident with the monthly peak of the Zone where the Network Customer load is physically located. Where a Network Customer has Network Load in more than one Zone, the monthly Network Load will be determined separately for each Zone. Where a Network Customer has designated Network Load not physically interconnected with the Transmission System under Section 31.4, the Network Customer's monthly Network Load will be its hourly load coincident with the monthly peak of the Zone that is the basis for charges under Schedule 9.

N - Definitions

Native Load Customers: The wholesale and retail power customers of the Transmission Owner(s) on whose behalf the Transmission Owner(s), by statute, franchise, regulatory requirement, or contract, has (have) undertaken an obligation to construct or operate the Transmission Owner's(s') system(s) to meet the reliable electric needs of such customers. In addition, Native Load Customers also may include the customers of the Federal Government on whose behalf the Government, by policy, statute, regulatory requirement, or contract, delivers Federal capacity and energy to meet all or a portion of the reliable electric needs of such customers.

Network Customer: An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

Network Customer Transmission Credits: Financial credits applied against a Network Customer's monthly demand charges under Schedule 9 of this Tariff in accordance with the provisions of Section 30.9 of the Tariff.

Network Integration Transmission Service: The transmission service provided under Part III of the Tariff.

Network Load: The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

Network Operating Agreement: An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

Network Resource: Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Upgrades: All or a portion of the modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all Users of such Transmission System.

Next-Hour-Market Service: Non-firm transmission service that (a) is reserved for one clock hour and (b) is requested within sixty (60) minutes before the start of the next clock hour for service commencing at the start of that clock hour.

Non-Firm Point-To-Point Transmission Service: Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

Non-Firm Sale: An energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

Notification to Construct ("NTC"): A written notice from the Transmission Provider directing an entity that has been selected to construct one or more transmission project(s)to begin or continue implementation of the transmission project(s) in accordance with Attachment Y.

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' SIXTH SET OF REQUESTS FOR INFORMATION

Question No. TIEC 6-3:

Referring to SWEPCO's response to TIEC 1-7:
a. Please provide all SPP documents, including FERC Orders, supporting SPP's decision to bill SWEPCO for NITS service for behind-the-meter retail load being served by Eastman Chemical Company effective in October 2018.

b. Please confirm that, prior to October 2018, SWEPCO was not billed by SPP for retail behind-the-meter load.

c. Please provide all documents prepared by AEP that address the appropriateness or inappropriateness of SPP's decision to bill SWEPCO for NITS service for behind-the-meter retail load.

Response No. TIEC 6-3:

a) Please see TIEC 6-3 Attachment 1 which is a report delivered to the SPP Market and Operations Policy Committee in March 2018. In addition, please see Attachment 2 for a presentation delivered more recently to the MOPC on this issue.

b) Confirmed. At this time SWEPCO has not been billed prior to that date.

c) Although AEP participated in discussions with SPP & other SPP Members concerning SPP's practice regarding behind-the-meter load as identified in Attachments 1 and 2, no responsive documents prepared by AEP have been located.

Prepared By: Earlyne T. Reynolds	Title: Reg Pricing & Analysis Mgr
Prepared By: C. Richard Ross	Title: Dir Trans RTO Policy
Sponsored By: Jennifer L. Jackson	Title: Reg Pricing & Analysis Mgr


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TO KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE.
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Network Load Reporting

March 28, 2018

Grandfathered Loads – Discussion Points

- What would exempt GFA from a Resident Load amount?
  - Pseudo-Tied to another Zone?
  - GFA Sinking in another Zone or exiting the region?
  - SPP PTP in the continuous transmission path of the GFA?
  - Other?

- What MW to report?
  - Reserved amount vs. Schedule amount

Behind-The-Meter (BTM) MW

- Multiple responses showed "non-standard" treatment, with BTM MW not being included in Network Load amounts
- Reported exceptions:
  - "At this time, we are not adding in generation consumed behind a retail meter."
  - "XX has interpreted the combination of btmg registration requirements in SPP Protocols 6 and in OATT Attachment AE, Section 2.2(6), and the definition of Network Load in NITSA Section 2.0 and in OATT 34.4 to be such that small (loads)...are netted against Network Load."
  - "XX is netted against Network Load, but is behind a retail meter and should be ignored no matter what."
  - "We do not add the solar farm gen into our peak because it's a BTM, unregistered, and undispatchable resource. In real time when it operates, it will reduce our SPP load by its output, and it also reduces our reported NITS one-hour peak load by the solar farm output. We use the same number for both the monthly number and the PYCP. We only add the solar farm generation back in when reporting our total load for the month on the Net Energy for Load form, and also in the Resource Adequacy Workbook."

Behind-The-Meter (BTM) MW

- Reported exceptions continued:
  - "This unit is not registered in the Marketplace because of the aforementioned inability to feed into the transmission system(s). This unit is strictly used for two purposes: offset usage and allow for emergency load support during outages."
  - "However, the BTM generators that are not registered with the market do reduce down the load before it is reported. "
  - "XX does not currently include end-use customer-owned generation that is behind the retail meter in the TC NITS Load calculation."
  - "With regards to NITS, no, we do not currently add BTM generation to our reported NITS load, per our internal interpretation of "BTM"."
  - "All behind the Meter Gen if running at the peak is included in NITS reporting. An exception to this is retail customers that have generation behind the retail meter. We have no way of metering solar panels for example behind retail meters."
  - "Awaiting final determination and establishment of rules/guidance from SPP"

Behind-The-Meter (BTM) MW

- Reported exceptions continued:
  - "All BTM generation is netted against NITS Load."
  - "...XX references SPP's ongoing discussion about 1MW threshold - looking for agreed upon guidance."
  - "XX and the XX have numerous small backup generators at our plants, control centers and microwave sites. These backup generators are never synchronized to the power system so we did not include them in our response."

Behind-The-Meter – Discussion Points

- What would exempt BTM MW from a Network Load amount?
  - Behind the retail meter vs. wholesale meter?
  - Generator not synchronized to the Transmission System?
  - BTM MW < X MW?
  - Can BTM MW net against Network Load reported?
  - Does market registration affect whether the generation is reported?

- Different Treatment for:
  - Transmission Billing
  - Resource Adequacy / Planning
  - Integrated Marketplace Billing

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MOPC POLICY SURVEY: BEHIND-THE-METER GENERATION

MARKET & OPERATIONS POLICY COMMITTEE

OCTOBER 15-16, 2019

Helping our members work together to keep the lights on... today and in the future.

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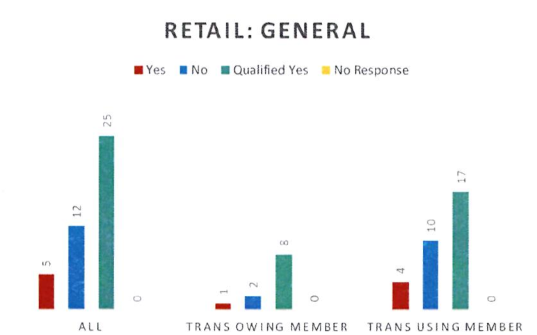
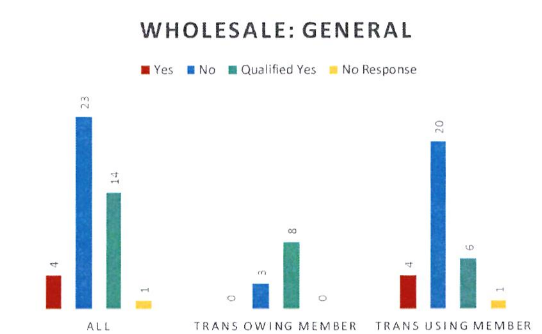
HIGH-LEVEL TAKEAWAY
RETAIL VS WHOLESALE BTMG NETTING

Retail: General	
For the purposes of reporting Network Load, should retail behind-the-meter generation be netted? In other words, should behind-the-meter generation be exempt from being added back to metered load?	
5	Yes. Netting of all generation behind the retail meter should be allowed regardless of other circumstances.
12	No. All load should be reported as gross (i.e. no netting of "any" behind-the-meter generation, including behind the retail meter).
25	Qualified Yes. Netting should be allowed under some circumstances (further detailed in responses to questions below)
0	No Response

Wholesale: General	
Should wholesale behind-the-meter generation be netted for the purposes of reporting Network Load? In other words, should wholesale behind-the-meter generation be exempted from being added back to the metered load?	
4	Yes. All generation behind the wholesale meter should be netted regardless of any other circumstances.
23	No. All load should be reported as gross (i.e. no netting of any wholesale behind-the-meter generation).
14	Qualified yes. Netting should be allowed under some circumstances (further detailed in responses to questions below).
1	No Response





- There appears to be interest in allowed netting for generation behind the retail meter under certain circumstances
- There is far less interest in netting for generation behind a wholesale meter but in front of a retail meter

SPP

ORIGINAL

RIMS Electric

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services By Public Utilities	)))	Docket No. RM95-8-000
	)	
Recovery of Stranded Costs By Public Utilities and Transmitting Utilities	))	Docket No. RM94-7-001

INITIAL COMMENTS
OF
CAJUN ELECTRIC POWER COOPERATIVE, INC.

Sharon C. Rochford
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August 7, 1995

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many years under Operating Agreements that generally work and which already provide for interconnection standards from the standpoint of both operations and facilities. Although Cajun recognizes that some legitimate modifications to existing agreements may be necessary, the Commission should make clear that switching to the open access Network Transmission Tariff envisioned in the Proposed Rulemaking should not burden an existing customer with new, onerous, and unnecessary operational, informational or hardware requirements. Additionally, any Network Operating Agreement filed by a public utility as part of its open access requirement should be subject to the same rigorous standards as other filings before being accepted by the Commission.

B. Credits for Customer-Owned Transmission Facilities

It is imperative that the Commission set clear standards for the identification of customer-owned transmission facilities subject to crediting and clear guidelines for the determination of the amount of the credit. Without such clear standards extensive and protracted litigation is inevitable. Cajun's litigation with GSU over the implementation of their CTOC agreement is an obvious example of the type of litigation that the Commission and all parties should want to avoid. Cajun Electric Power Cooperative, Inc. v. Gulf States Utilities Company, Docket Nos. EL87-51-000 and ER88-477-000.

The standards and guidelines adopted by the Commission must treat customers and transmission providers equally with respect to the identification of facilities that are considered part of the grid for crediting and revenue requirements purposes, respectively, and those that are not. These standards should apply to existing facilities as well as future facilities (see discussion of Direct Assignment Facilities and Network Upgrades at Part V(C), above). The bottom line of such an approach is that any facility that would be included in the transmission revenue requirement if owned by the transmission provider should be included in the determination of the transmission customer's credit.

The credit for such facilities should be equivalent to the amount associated with those facilities that would be included in the transmission providers' transmission revenue requirement if the transmission provider owned the facilities.

Alternatively, the Commission could make a determination each year of a generic fixed charge rate to be applied to customer owned facilities. Only through an approach, such as one of these, will transmission owning utilities and TDU's, who are being asked to pay their load ratio share of the costs, truly be on an equal playing field.

Transmission providers may argue that they should not be required to include in their revenue requirement the cost of facilities that primarily benefit one user, and only provide marginal benefits to the grid. If the Commission agrees with this argument, then it must also agree with and implement the flip side of the argument, i.e., that the transmission customers should not be required to pay the costs of the transmitting utilities' facilities that are used primarily for service to its own customers and only marginally benefit the grid. All comparable facilities should either be "in" or "out", regardless of ownership. The standards adopted by the Commission must be uniform and consistent for the transmission provider and its customers and encompass both existing and future facilities.

C. Network Loads/Load Ratio Share

A network customer's load ratio share, simply put, should be the ratio of the customer's load on the grid to the total load on the grid at the time of the coincident peak. Total load on the grid should include the transmission provider's own native retail loads, requirements and other power supply loads of the transmission provider, all network customers' loads on the grid, and all firm non-network transmission loads. In allocating the revenue requirement, all uses of the grid, except for use by network customers, should be allocated to the transmission provider.

The Commission defines the network customer's network load on the grid as equal to the loads of designated members including loads served behind the meter. There are two distinct problems with this definition. First, as discused above in the description of Cajun, a network customer's members may be served off of the transmission systems of more than one transmitting utility. By defining network load as including the total load of designated members, the Commission may be forcing a transmission customer to pay twice or even thrice for network service to its member. The solution is obvious -- the transmission customer's network load should be defined as loads to designated delivery points, not members. This definition should include loads to designated delivery points on the transmission provider's system, as well as loads to designated delivery points on other transmission providers' systems which require interconnection transmission service from the subject transmission provider.

The second problem in the Commission's definition of network load is the inclusion of loads that are being served by generation located behind the delivery point. Although the Commission discussed this matter in the Florida Municipal Power Agency case, it left the door open to revisit this issue in other situations [67 FERC ¶ 61,167 at 61,481 n.74 (1994)]. Cajun makes three arguments regarding this issue.

First, a transmission provider may also have "generation behind the meter" that is not being included in its load ratio share. This can happen when the utility has a QF on its system, which is serving its own needs. However, since the utility has an obligation to provide standby and supplemental service to such a QF, the entire load of the QF is technically part of the utility's load, but it is being served by generation "behind" the utility's meter. To be consistent with including the network customer's loads being served "behind" the meter in its load ratio share, the transmitting utility should be required to include all such QF loads in its load ratio share. However, the better answer is to exclude such loads of both and include only loads which actually use the grid.

Secondly, Cajun questions the argument that the transmission provider's transmission system is being used to integrate the customer's entire load and therefore the entire load should be included as part of the customer's load ratio share. Depending on the facts and circumstances of individual cases, this may or may not always be true. The Commission is wrong in assuming that it is always true that the entire load of the member is being integrated and therefore wrong in automatically including the entire load in the customer's load ratio share. The transmission customer should be allowed to designate which portion of its loads it desires to integrate.

Finally, the transmission provider planned its system to integrate its own loads, whereas the TDU has to serve its loads by using a hybrid of other utilities' grids and its own facilities. Requiring the TDU to pay a load ratio share of a grid planned for someone else's system and then requiring it to include in that load ratio share its loads being served by other means results in a double penalty to the TDU. Cajun will not pursue here the argument that paying a load ratio share of the transmission provider's transmission revenue requirement is inequitable because the transmission provider's system was built to serve its load not that of the TDU, but does argue that adding loads behind the meter to the load ratio share results in an unwarranted unleveling of the playing field.

D. Revenue Crediting

Since the network customer will be paying a load ratio share of the costs of the transmission network, the customer should receive its load ratio share of excess revenues derived from the use of the transmission grid. Specifically, under the formulae in the proforma tariffs, the load ratio share concept is based on the volume of firm long-term transmission use by all users at the time of the coincident peak. (The Commission defines long-term as at least one year.) However, the transmission provider derives additional revenues from off-peak, non-firm and/or short-term transmission services. The transmission provider may also be receiving revenues from contracted firm long-term transmission service in excess of the actual amount of transmission service occurring at the time of the peak, as well as revenues from ancillary services, the costs of which may already be included in the transmission revenue requirement. All of these "excess" transmission revenues should be shared with network customers, who are paying for the costs of the system, on a load ratio basis. This is easily implemented. If the rates are based on a formula which is to be updated annually, then the excess transmission revenues in the test year period would simply be credited against the revenue requirement before applying the load ratio share concept. If the rates are not formula rates, but instead are fixed rates, then a monthly "tracker" could be used to credit back to the network customer its load ratio share of excess transmission revenues in each month. The "excess" transmission revenues discussed herein must, obviously, include revenues that the transmission provider is charging and paying to itself.

E. New Interconnection and Delivery Points

Section 6.4 of the Network Transmission Tariff addresses the issue of new interconnection points; however, the Commission does not define "interconnection point" in the tariff. Under standard industry usage, there is generation on both sides of an "interconnection point". In contrast, Cajun and other TDU's serve their loads through "delivery points" which generally have no generation behind them. The Commission should clarify that its intent in this section is to discuss both delivery points, i.e., points of connection that serve load centers, as well as points of

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ORIGINAL

Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities	Docket Nos. RM95-8-000 and RM94-7-001

RIMS Electric

REQUEST FOR CLARIFICATION AND REHEARING OF AMERICAN MUNICIPAL POWER-OHIO, INC.

American Municipal Power-Ohio, Inc. (AMP-Ohio) supports and encourages the Commission's deliberate steps to ensure nondiscriminatory transmission access and to create the necessary structures to increase competition in wholesale power markets. As with any regulatory undertaking of this magnitude, the Commission's determinations in some instances are unclear or could harm the interests of AMP-Ohio and its members. Therefore, AMP-Ohio seeks clarification or, in the alternative, rehearing pursuant to Commission Rule 713. 18 C.F.R. § 385.713.

AMP-Ohio requests that the Commission clarify or grant rehearing regarding the following:

- The Commission should require transmission arrangements that are regionally based, avoid the pancaking of rates, permit dynamic scheduling and rely upon an independent system operator.
- The Commission's standards for crediting customer-owned transmission facilities must treat all facilities, whether owned by the transmission provider or transmission customer, in a comparable manner.

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evidence that the transmission provider's load flow studies take into account the transmission customer's facilities. The standard should not be a subjective one that depends on whether the transmission provider *says* that it includes customer facilities in its planning and operations.

For example, the deposition excerpt (pp. 18-26 of deposition) in Attachment A hereto of AEP Vice President Raymond M. Maliszewski demonstrates that in AEP's load flow studies customer-owned facilities are taken into account in a manner comparable to AEP's own. Just as AEP's facilities may be modeled into a load flow study depending upon the purpose of the study, so too the facilities of AEP's TDUs may be included. Evidence that the customer facilities are taken into account should suffice to satisfy the "operation and planning" requirement.[7] The standard should not be whether, in the context of the specific case determining the appropriate credit, the transmission provider admits that it takes such facilities into account.

Other evidence that the network customer has satisfied the crediting standard should include whether the transmission provider includes in rate base or transmission expenses costs associated with transmission owned utilities which it acquires. For example, AEP acquired the former municipally-owned utility of Ft. Wayne, Indiana and now includes the costs of the Ft. Wayne transmission facilities in transmission rates. When asked whether the facilities at Ft. Wayne provide "measurable benefits" to the AEP system, AEP responded:

> The 34.5 kV facilities leased from the city of Fort Wayne cover a limited geographical area. However, they do

[7] Of course, such evidence should not be the only way by which the standard is satisfied.

> provide measurable benefits to the AEP System, since they provide the principal means for delivering AEP's generation to those I&M customers formerly served by the city of Ft. Wayne.

See Attachment C to Initial Comments of AMP-Ohio and Indiana Municipal Power Agency in Docket No. RM95-8-000, *et al.* AMP-Ohio submits that if AEP were to acquire any of AMP-Ohio's members today, AEP would include the costs of the acquired utility's transmission in AEP's transmission rates, just as it has with Ft. Wayne. Thus, regardless of whether AEP or AMP-Ohio owns or rents the transmission facilities, they should receive recognition as part of the transmission grid.

C. The Commission Should Clarify the Network Load Definition to Enable Transmission Customers to Use Network Service

TAPS and AMP-Ohio, through the TAPS Rehearing, are requesting clarification of the definition of Network Load, Tariff § 1.22, to ensure that it is consistent with the Final Rule's conclusions that network customers be able to exclude a particular load at discrete points of delivery, for example, to eliminate from Network Integration Transmission Service load served from behind the meter generation. Final Rule at 297, 317. AMP-Ohio emphasizes here the importance of this issue to enabling AMP-Ohio to integrate at least portions, if not all, of its and its members loads and resources, using the Network Integration Transmission Service provided for in the Pro Forma Tariff, particularly if transmission providers are not required to give AMP-Ohio and its members credits for their transmission facilities.

For example, AMP-Ohio is one of numerous TDUs across the country whose members have installed generation and transmission to serve local loads. Oftentimes, these installations were made at the insistence of transmission providers, such as AEP, who demanded that a certain amount of generation be located "behind the meter" to provide reserves. Because the utilities with such generation generally have transmission facilities that can be used to integrate the generation with local loads and that also provide support to the broader transmission grid, these facilities should receive credits under the Pro Forma Tariff, as described above. Such credits would also make it more likely that AMP-Ohio can use such generation to serve other loads through Network Integration Transmission Service, a result that otherwise could not occur without the customer-owned transmission facilities.

AMP-Ohio should also be permitted decide that it will serve a portion of the load from this behind the meter generation and not include the load in Network Integration Transmission Service, therefore not requiring the transmission provider to provide such service to the loads. Such exclusion is critical if AMP-Ohio cannot receive credits for its own or its members' transmission facilities, and the exclusion should be permitted, even if it does not involve the totality of the load at a discrete delivery point. So long as the transmission customer compensates the transmission provider for any uses of the transmission grid, the transmission customer should be permitted to determine that it will use that grid on point-to-point or network basis, or not use the grid at all.

This issue can make the difference between whether AMP-Ohio can use the Network Integration Transmission Service included in the Pro Forma Tariff, or whether AMP-Ohio will have to rely on point-to-point services that would not permit it to engage in the kind of economic dispatch that transmission providers are able to do. Therefore, AMP-Ohio urges the Commission to give special heed to the TAPS rehearing on the of the Network Load definition.

D. The Commission Should Modify Its "Rebuttable Presumption" to an "Irrebuttable Presumption," At Least in States Where Transmission Access and Competition Have Existed for Decades

On the issue of stranded cost recovery, TAPS and AMP-Ohio have asked the Commission to establish a few ground rules that might have the effect of discouraging completely unfounded claims of stranded costs brought only to intimidate or threaten customers who seek new power suppliers. AMP-Ohio separately notes that where transmission access and competition have existed to varying extents for decades, the Commission's "rebuttable presumption," Regulation § 35.26(c)(3), should be "irrebuttable." Indeed, such circumstances are no different than the ability of a municipality to expand its territory through annexation, a situation where the Commission states that "there is no direct nexus between the FERC-jurisdictional transmission access requirement and the exposure to non-recovery of prudently incurred costs." Final Rule at 536.

There is a long history of competition in Ohio. Since 1912 the Ohio Constitution has guaranteed the rights of a municipality to create new municipal electric utility systems, should a municipality so desire, or to award a competing or new franchise to a different utility, municipal or otherwise. Ohio's certified territory act explicitly recognizes these municipal rights to create new municipal electric utilities or award separate franchises and specifically exempts municipal utilities from the act. *See* 4933.81 *et seq*, Ohio Revised Code. Indeed, prior to 1978, Ohio did not have certified territories and, accordingly, Ohio IOUs had no "exclusive right and statutory obligation to serve." There was competition for loads among IOUs, municipals and cooperatives.[8] Thus, many decisions with respect to nuclear assets, for example, made prior to 1978 were made without a basis for a utility to conclude that its present or future customers could not obtain power supply elsewhere.

More importantly, as a result of litigation, interventions in merger applications, negotiations and the imposition of nuclear license conditions after antitrust review, transmission access has been available to both new and existing municipal systems in Ohio for decades. While the access may have been less than perfect or "comparable" in some respects, it has been workable and served Ohio well.

Ohio has had and continues to have a measure of healthy competition at both the wholesale and retail levels. Indeed, many electric customers in Ohio already have a choice of providers as a result of door-to-door competition in and around communities with municipal electric systems. Utilities should not be given a new tool to frustrate further development of this pre-existing competition by claims of "stranded costs" under the guise of new open access rules and filings.

Open access did not bring competition to Ohio. Instead, competition has been a part of the state's landscape for years, and transmission rights have been gained by Ohio's municipal utilities through hard-fought efforts. The "rebuttable presumption" should not operate to revise this history, chill the expansion of existing municipal systems

[8] Prior to 1978, Ohio did have an "anti-piracy law" which did provide some limitation on service changes for existing, as opposed to new, customers among IOUs. There has never been protection from competition from municipal systems, although the Ohio Constitution does limit a municipal's kWh sales outside its municipal limits to fifty percent of that used inside its municipal limits.

61 FR 21540-01
RULES and REGULATIONS
DEPARTMENT OF ENERGY
Federal Energy Regulatory Commission
18 CFR Parts 35 and 385
[Docket Nos. RM95-8-000 and RM94-7-001; Order No. 888]

Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities

Friday, May 10, 1996

***21540** Issued April 24, 1996.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is issuing a Final Rule requiring all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to have on file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service. The Final Rule also permits public utilities and transmitting utilities to seek recovery of legitimate, prudent and verifiable stranded costs associated with providing open access and Federal Power Act section 211 transmission services. The Commission's goal is to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers.
EFFECTIVE DATE: This Final Rule will become effective on July 9, 1996.

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SUPPLEMENTARY INFORMATION: In addition to publishing the full text of this document in the Federal Register, the Commission also provides all interested persons an opportunity to inspect or copy the contents of this document during normal business hours in the Public Reference Room at 888 First Street, NE., Washington, DC 20426.
The Commission Issuance Posting System (CIPS), an electronic bulletin board service, provides access to the texts of formal documents issued by the Commission. CIPS is available at no charge to the user and may be accessed using a personal computer with a modem by dialing 202-208-1397 if dialing locally, or 1-800-856-3920 if dialing long distance. CIPS is also available through the Fed World system (by modem or Internet). To access CIPS, set your communications software to 19200, 14400, 12000, 9600, 7200, 4800, 2400, or 1200 bps, full duplex, no parity, 8 data bits and 1 stop bit. The full text of this order will be

available on CIPS indefinitely in ASCII and WordPerfect 5.1 format. The complete text on diskette in Wordperfect format may also be purchased from the Commission's copy contractor, La Dorn Systems Corporation, also located in the Public Reference Room at 888 First Street NE., Washington, DC 20426.

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I. Introduction/Summary

Today the Commission issues three final, interrelated rules designed to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers.[FN1] The legal and policy cornerstone of these rules is to remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce. A second critical aspect of the rules is to address recovery of the transition costs of moving from a monopoly-regulated regime to one in which all sellers can compete on a fair basis and in which electricity is more competitively priced.

In the year since the proposed rules were issued,[FN2] the pace of competitive changes in the electric utility industry has accelerated. By March of last year, 38 public utilities had filed wholesale open access transmission tariffs with the Commission. Today, prodded by such competitive changes and encouraged by our proposed rules, 106 of the approximately 166 public utilities that own, control, or operate[FN3] transmission facilities used in interstate commerce have filed some form of wholesale open access tariff. In addition, since the time the proposed rules were issued, numerous state regulatory commissions have adopted or are actively evaluating retail customer choice programs or other utility restructuring alternatives. These events have been spurred by continuing pressures in the marketplace for changes in the way electricity is bought, sold, and transported. Increasingly, customers are demanding the benefits of competition in the growing electricity commodity market.

The Commission estimates the potential quantitative benefits from the Final Rule will be approximately $3.8 to $5.4 billion per year of cost savings, in addition to the non-quantifiable benefits that include better use of existing assets and institutions, new market mechanisms, technical innovation, and less rate distortion. The continuing competitive changes in the industry and the prospect of these benefits to customers make it imperative that this Commission take the necessary steps within its jurisdiction to ensure that all wholesale buyers and sellers of electric energy can obtain non-discriminatory transmission access, that the transition to competition is orderly and fair, and that the integrity and reliability of our electricity infrastructure is maintained.

In this Rule, the Commission seeks to remedy both existing and future undue discrimination in the industry and realize the significant customer benefits that will come with open access. Indeed, it is our statutory obligation under sections 205 and 206 of the Federal Power Act (FPA) to remedy undue discrimination.

To do so, we must eliminate the remaining patchwork of closed and open jurisdictional transmission systems and ensure that all these systems, including those that already provide some form of open access, cannot use monopoly power over transmission to unduly discriminate against others. If we do not take this step now, the result will be benefits to some customers at the expense of others. We have learned from our experience in the natural gas area the importance of addressing competitive transition issues early and with as much certainty to market participants as possible.

Accordingly, in this proceeding and in the accompanying proceeding on OASIS, the Commission, pursuant to its authorities under sections 205 and 206 of the FPA:

- Requires all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce

- To file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service;

- To take transmission service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the open access tariffs;

- To develop and maintain a same-time information system that will give existing and potential transmission users the same access to transmission information that the public utility enjoys, and further requires public utilities to separate transmission from generation marketing functions and communications;

- Clarifies Federal/state jurisdiction over transmission in interstate commerce and local distribution and provides for deference to certain state recommendations; and

- Permits public utilities and transmitting utilities to seek recovery of legitimate, prudent and verifiable stranded costs associated with providing open access and FPA section 211 transmission services.

Open Access

The Final Rule requires public utilities to file a single open access tariff that offers both network, load-based service and point-to-point, contract-based service. The Rule contains a pro forma tariff that reflects modifications to the NOPR's proposed terms and conditions and also permits variations for regional practices. All public utilities subject to the Rule, including those that already have tariffs on file, will be required to make section 206 compliance filings to meet the new pro forma tariff non-price minimum terms and conditions of non-discriminatory transmission. Utilities may propose their own rates in a section 205 compliance filing.

The Rule provides that public utilities may seek a waiver of some or all of the requirements of the Final Rule. In addition, non-public utilities may seek a waiver of the tariff reciprocity provisions.

The Final Rule does not generically abrogate existing requirements contracts, but will permit customers and public utilities to seek modification, or termination, of certain existing requirements contracts on a case-by-case basis. As to coordination arrangements and contracts, the Rule finds that these arrangements and contracts may need to be modified to remove unduly discriminatory transmission access and/or pricing provisions. Such arrangements and agreements include power pool agreements, public utility ***21542** holding company agreements, and certain bilateral coordination agreements. The Rule provides guidance and timelines for modifying unduly discriminatory coordination arrangements and contracts, and specifies when the members of such arrangements must begin to conduct trade with each other using the same open access tariff offered to others. The Rule also provides guidance regarding the formation of independent system operators (ISOs).

The Rule does not require any form of corporate restructuring, but will accommodate voluntary restructuring that is consistent with the Rule's open access and comparability policies.

As discussed in the NOPR, not all owners or controllers of interstate transmission facilities are subject to the Commission's jurisdiction under sections 205 and 206 of the FPA and therefore are not subject to this Rule's open access requirements. Therefore, the Final Rule retains the proposed reciprocity provision in the pro forma tariff. Without such a provision, non-open access utilities could take advantage of the competitive opportunities of open access, while at the same time offering inferior access, or no access at all, over their own facilities. Thus, open access utilities would be unfairly burdened. We note that some non-jurisdictional utilities have expressed an interest in a mechanism for obtaining a Commission determination that their transmission tariffs satisfy the reciprocity provisions in the pro forma tariffs, and we provide such a mechanism in the Rule.

The Final Rule does not generically provide for market-based generation rates. Although the Rule codifies the Commission's prior decision that there is no generation dominance in new generating capacity, intervenors in cases may raise generation dominance issues related to new capacity. In addition, to obtain market-based rates for existing generation, we will continue to require public utilities to show, on a case-by-case basis, that there is no generation dominance in existing capacity. Further, in all market-based rate cases, we will continue to look at whether an applicant and its affiliates could erect other barriers to entry and whether there may be problems due to affiliate abuse or reciprocal dealing.

Finally, contemporaneously with this Rule the Commission issues an NOPR on capacity reservation tariffs as an alternative, and perhaps superior, means of remedying undue discrimination.

Transmission/Local Distribution

The Rule clarifies the Commission's interpretation of the Federal/state jurisdictional boundaries over transmission and local distribution. While we reaffirm our conclusion that this Commission has exclusive jurisdiction over the rates, terms, and conditions of unbundled retail transmission in interstate commerce by public utilities, we nevertheless recognize the very legitimate concerns of state regulatory authorities as they contemplate direct retail access or other state restructuring programs. Accordingly, we specify circumstances under which we will give deference to state recommendations. Although jurisdictional boundaries may shift as a result of restructuring programs in wholesale and retail markets, we do not believe this will change fundamental state regulatory authorities, including authority to regulate the vast majority of generation asset costs, the siting of generation and transmission facilities, and decisions regarding retail service territories. We intend to be respectful of state objectives so long as they do not balkanize interstate transmission of power or conflict with our interstate open access policies.

Stranded Costs

With regard to stranded costs, the Final Rule adopts the Commission's supplemental proposal. It will permit utilities to seek extra-contractual recovery of stranded costs associated with a limited set of existing (executed on or before July 11, 1994) wholesale requirements contracts and provides that the Commission will be the primary forum for utilities to seek recovery of stranded costs associated with retail-turned-wholesale transmission customers. It also will allow utilities to seek recovery of stranded costs caused by retail wheeling only in circumstances in which the state regulatory authority does not have authority to address retail stranded costs at the time the retail wheeling is required. The Rule retains the revenues lost approach for calculating stranded costs and provides a formula for calculating such costs.

Environmental Issues

The Commission has prepared a Final Environmental Impact Statement (FEIS) evaluating the possible environmental consequences of changes in the bulk power marketplace expected to occur as a result of the open access requirements of this Final Rule. The FEIS focuses, as do most commenters, on possible increases in emissions of nitrogen oxides (NO_X) from certain fossil-fuel fired generators, which could affect air quality in the producing region and in areas to which these emissions may be carried.

In response to comments on the Draft EIS, the Commission performed numerous additional studies. The FEIS finds that the relative future competitiveness of coal and natural gas generation is the key variable affecting the impact of the Final Rule. If competitive conditions favor natural gas, the Rule is likely to lead to environmental benefits. Both EPA and the Commission staff believe this projected scenario is the more likely one. If competitive conditions favor coal, the Rule may lead to small negative environmental impacts. However, even using the most extreme, unlikely assumptions about the future of the industry, the negative consequences are not likely to occur until after the turn of the century. Because the impacts will remain modest at least until 2010, there is no need for an interim mitigation program. In addition, even if the data showed more significant negative consequences requiring mitigation, the Commission does not have the statutory authority under the Federal Power Act or the expertise to address this possible far-term problem. The Commission believes, however, that there is time for federal and state air quality authorities to address any potential adverse impact as part of a comprehensive NO_X regulatory program under the Clean Air Act.[FN4]

Despite our conclusions regarding the lack of environmental impacts expected to result from the Rule, the Commission has examined a wide variety of proposals for mitigating possible adverse effects. We share the view of most commenters that the preferred approach for mitigating increased NO_X emissions generally is a NO_X cap and trading regulatory program comparable to that developed by Congress to address sulfur dioxide emissions in the Clean Air Act Amendments of 1990.[FN5] The Commission has examined various means of establishing such a program, including use of existing federal authorities under the Clean Air Act, cooperative efforts by state and federal air quality regulators, and development of a new emissions regulatory program administered by the Commission under the Federal Power Act. The Commission has concluded that a NO_X regulatory program could best be developed and administered under the Clean Air Act, in cooperation with interested states, and offers to lend Commission support ***21543** to that effort should it become necessary.

Conclusion

The Commission believes that the Final Rule will remedy undue discrimination in transmission services in interstate commerce and provide an orderly and fair transition to competitive bulk power markets.

II. Public Reporting Burden

The Open Access Final Rule and the Stranded Cost Final Rule specify filing requirements to be followed by public utilities that own, control or operate transmission facilities in interstate commerce in making non-discriminatory open access tariff filings and filings to recover legitimate, prudent and verifiable stranded costs. The information collection requirements of the final rules are attributable to FERC-516 "Electric Rate Filings." The current total annual reporting burden for FERC-516 is 828,300 hours.

A. Docket No. RM95-8-000 (Open Access Final Rule)

The Open Access Final Rule requires public utilities filing non-discriminatory open access tariffs to provide certain information to the Commission. The Commission estimated that the public reporting burden for the information collection would average 300 hours per response. This estimate included time for reviewing the requirements of the Commission's regulations, searching existing data sources, gathering and maintaining the necessary data, completing and reviewing the collection of information, and filing the revised information. No comments on the burden estimate were received. Because the Final Rule adopts essentially the same information requirements that are contained in the proposed rule, we believe that the average filing burden is same for the Final Rule.

In the proposed rule, the Commission noted that there are approximately 328 public utilities, including marketers and wholesale generation entities. We initially estimated that 137 public utilities own, control or operate facilities used for the transmission of electric energy in interstate commerce, and would be subject to the filing requirements of the proposed rule. Upon further review, the Commission believes that approximately 166 public utilities will respond to the information collection. Accordingly, the public reporting burden is estimated to be 49,800 hours.

B. Docket No. RM94-7-001 (Stranded Cost Final Rule)

In the supplemental notice of proposed rulemaking, the Commission estimated that the information requirements of the proposed rule would not differ substantially from those contained in the initial proposed rule. In that notice, the Commission estimated that the public reporting burden for the information requirements contained in the proposed rule would be 50 hours per response with 10 responses annually. No comments on this filing burden were received. The information requirements adopted in the Stranded Cost Final Rule are not substantially different from those in the proposed rule. Therefore, the Commission concludes that there will be no additional public filing burden associated with the Stranded Cost Final Rule.

III. Background

In the NOPR, we set out a detailed statement of the events leading up to this rulemaking. We repeat that background here, updated to reflect what has happened since March 1995, and discuss why it is necessary to undertake regulatory reform in the electric industry at this time. We do so to provide the necessary backdrop to our action in adopting this Rule.

A. Structure of the Electric Industry at Enactment of Federal Power Act

The Federal Power Act was enacted in an age of mostly self-sufficient, vertically integrated electric utilities, in which generation, transmission, and distribution facilities were owned by a single entity and sold as part of a bundled service (delivered electric energy) to wholesale and retail customers. Most electric utilities built their own power plants and transmission systems, entered into interconnection and coordination arrangements with neighboring utilities, and entered into long-term contracts to make wholesale requirements sales (bundled sales of generation and transmission) to municipal, cooperative, and other investor-owned utilities (IOUs) connected to each utility's transmission system. Each system covered limited service areas. This structure of separate systems arose naturally due primarily to the cost and technological limitations on the distance over which electricity could be transmitted.

Through much of the 1960s, utilities were able to avoid price increases, but still achieve increased profits, because of substantial increases in scale economies, technological improvements, and only moderate increases in input prices.[FN6] Thus, there was no pressure on regulatory commissions to use regulation to affect the structure of the industry.[FN7]

B. Significant Changes in the Electric Industry

In the late 1960s and throughout the 1970s, a number of significant events occurred in the electric industry that changed the perceptions of utilities and began a shift to a more competitive marketplace for wholesale power.[FN8] This was the beginning of periods of rapid inflation, higher nominal interest rates, and higher electricity rates.[FN9] During this time, consumers became concerned about higher electricity rates and questioned any price increases filed by utilities.[FN10]

During this same time frame, the construction of nuclear and other capital-intensive baseload facilities—actively encouraged by federal and some state governments—contributed to the continuing cost increases and uncertainties in the industry.[FN11] These investments were made based on the assumptions that there would be steady increases in the demand for electricity and continued large increases in the price of oil.[FN12] However, due to conservation and economic downturns, the expected demand increases did not materialize. Load growth virtually disappeared in some areas, and many utilities unexpectedly found themselves with excess capacity.[FN13] In addition, by the 1980s, the oil cartel collapsed, with a resulting glut of low-priced oil. [FN14] At the same time, inflation substantially increased the costs of these large ***21544** baseload generating plants.[FN15] Surging interest rates further increased the cost of the capital needed to finance and capitalize these projects and completion schedules were significantly extended by, in part, more stringent safety and environmental requirements.[FN16]

As a result, expensive large baseload plants for which there was little or no demand, came onto the market or were in the process of being constructed. Accordingly, between 1970 and 1985, average residential electricity prices more than tripled in nominal terms, and increased by 25% after adjusting for general inflation.[FN17] Moreover, average electricity prices for industrial customers more than quadrupled in nominal terms over the same period and increased 86% after adjusting for inflation. [FN18]} The rapidly increasing rates for electric power during this period, together with the opportunities provided by the Public Utility Regulatory Policies Act of 1978 (PURPA) (discussed infra), also prompted some industrial customers to bypass utilities by constructing their own generation facilities. This further exacerbated rate increases for remaining customers—primarily residential and commercial customers.

Consumers responded to these "rate shocks" by exerting pressure on regulatory bodies to investigate the prudence of management decisions to build generating plants, especially when construction resulted in cost overruns, excess capacity, or both. Between 1985 and 1992, writeoffs of nuclear power plants totalled $22.4 billion.[FN19] These writeoffs significantly reduced the earnings of the affected utilities.[FN20] Delays in obtaining rate increases to reflect the effects of inflation further reduced investor returns. Thus, many utilities became reluctant to commit capital to long-term construction decisions involving large scale generating plants.[FN21]

In addition to economic changes in the industry, significant technological changes in both generation and transmission have occurred since 1935. Through the 1960s, bigger was cheaper in the generation sector and the industry was able to capitalize on economies of scale to produce power at lower per-unit costs from larger and larger plants.[FN22] As a result, large utility companies that could finance and manage construction projects of larger scale had a price advantage over smaller utility companies and customers who might otherwise have considered building their own generating units. Scale economies encouraged power generation by large vertically-integrated utility companies that also transmitted and distributed power. Beginning in the 1970s, however, additional economies of scale in generation were no longer being achieved.[FN23] A significant factor was that larger generation units were found to need relatively greater maintenance and experience longer downtimes.[FN24] The electric industry faced the situation "where the price of each incremental unit of electric power exceeded the average cost."[FN25] Bigger was no longer better.

Further dictating against larger generation units were advances in technologies that allowed scale economies to be exploited by smaller size units, thereby allowing smaller new plants to be brought on line at costs below those of the large plants of the 1970s and earlier. Such new technologies include combined cycle units and conventional steam units that use circulating fluidized bed boilers.[FN26]

The combined cycle generating plants generally use natural gas as their primary fuel. This technology has been made possible by the development of more efficient gas turbines, shorter construction lead times, lower capital costs, increased reliability, and relatively minimal environmental impacts.[FN27] Similarly, the circulating fluidized bed combustion boilers, fueled by coal and other conventional fuels, provide a more efficient and less polluting resource.

Today, "the optimum size (of generation plants) has shifted from (more than 500 MW) (10-year lead time) to smaller units (one-year lead time) (in the 50-to 150-MW range)."[FN28] Indeed, smaller and more efficient gas-fired combined-cycle generation facilities can produce power on the grid at a cost ranging from 5 cents per kWh to less than 3 cents per kWh.[FN29] This is significantly less than the costs for large plants constructed and installed by utilities over the last decade, which were typically in the range of 4 to 7 cents per kWh for coal plants and 9 to 15 cents for nuclear plants.[FN30] Significant changes have also occurred in the transmission sector of the industry. Technological advances in transmission have made possible the economic transmission of electric power over long distances at higher voltages.[FN31] This has ***21545** made it technically feasible for utilities with lower cost generation sources to reach previously isolated systems where customers had been captive to higher cost generation. In addition, the nature and magnitude of coordination transactions [FN32] have changed dramatically since enactment of the FPA, allowing increased coordinated operations and reduced reserve margins. Substantial amounts of electricity now move between regions, as well as between utilities in the same region. Physically isolated systems have become a thing of the past.

C. The Public Utility Regulatory Policies Act and the Growth of Competition

In enacting PURPA,[FN33] Congress recognized that the rising costs and decreasing efficiencies of utility-owned generating facilities were increasing rates and harming the economy as a whole.[FN34] To lessen dependence on expensive foreign oil, avoid repetition of the 1977 natural gas shortage, and control consumer costs, Congress sought to encourage electric utilities to conserve oil and natural gas.[FN35] In particular, Congress sanctioned the development of alternative generation sources designated as "qualifying facilities" (QFs) as a means of reducing the demand for traditional fossil fuels.[FN36] PURPA required utilities to purchase power from QFs at a price not to exceed the utility's avoided costs and to sell backup power to QFs.[FN37]

PURPA specifically set forth limitations on who, and what, could qualify as QFs. In addition to technological and size criteria, PURPA set limits on who could own QFs.[FN38] Notwithstanding these limitations, QFs proliferated. In 1989, there were 576 QF facilities. By 1993, there were more than 1,200 such facilities.[FN39] For the same time period, installed QF capacity increased from 27,429 megawatts to 47,774 megawatts.[FN40] The rapid expansion and performance of the QF industry demonstrated that traditional, vertically integrated public utilities need not be the only sources of reliable power.

During this period, the profile of generation investment began to change, and a market for non-traditional power supply beyond the purchases required by PURPA began to emerge. QFs were limited to cogenerators and small power producers.[FN41]

However, other non-traditional power producers who could not meet the QF criteria began to build new capacity to compete in bulk power markets, without such PURPA benefits as the mandatory purchase requirements. These producers, known as independent power producers (IPPs), were predominantly single-asset generation companies that did not own any transmission or distribution facilities. While traditional utilities were generally reluctant at that time to invest in new generating facilities under cost of service regulation, utilities increasingly became interested in participating in this new generation sector. They organized affiliated power producers (APPs), with assets not included in utility rate base, and sought to sell power in their own service territories and the territories of other utilities. At the same time, power marketers arose. These entities—owning no transmission or generation—buy and sell power.[FN42]

There were two major impediments to the development of IPPs and APPs. First, the ownership restrictions of the Public Utility Holding Company Act (PUHCA)[FN43] severely inhibited these new entities from entering the generation business.[FN44] Second, these entities needed transmission service in order to compete in electricity markets.

While the Commission had no authority to remove PUHCA restrictions,[FN45] it encouraged the development of IPPs and APPs, as well as emerging power marketers, by authorizing market-based rates for their power sales on a case-by-case basis and by encouraging more widely available transmission access. From 1989 through 1993, facilities owned by IPPs and other non-traditional generators (other than QFs) increased from 249 to 634 and their installed capacity increased from 9,216 megawatts to 13,004 megawatts.[FN46] Indeed, "[i]n 1992, for the first time, generating capacity added by independent producers exceeded capacity added by utilities."[FN47]

Market-based rates helped to develop competitive bulk power markets. A generating utility allowed to sell its power at market-based rates could move more quickly to take advantage of short-term or even long-term market opportunities than those laboring under traditional cost-of-service tariffs, which entail procedural delays in achieving tariff approvals and changes.

In approving these market-based rates, the Commission required, inter alia, that the seller and any of its affiliates lack market power or mitigate any market ***21546** power that they may have possessed.[FN48] The major concern of the Commission was whether the seller or its affiliates could limit competition and thereby drive up prices. A key inquiry became whether the seller or its affiliates owned or controlled transmission facilities in the relevant service area and therefore, by denying access or imposing discriminatory terms or conditions on transmission service, could foreclose other generators from competing.[FN49] As we have previously explained:

The most likely route to market power in today's electric utility industry lies through ownership or control of transmission facilities. Usually, the source of market power is dominant or exclusive ownership of the facilities. However, market power also may be gained without ownership. Contracts can confer the same rights of control. Entities with contractual control over transmission facilities can withhold supply and extract monopoly prices just as effectively as those who control facilities through ownership.[FN50]

As entry into wholesale power generation markets increased, the ability of customers to gain access to the transmission services necessary to reach competing suppliers became increasingly important.[FN51] In addition, beginning in the late 1980s, in order to mitigate their market power to meet Commission conditions, public utilities seeking Commission approval of mergers or consolidations under section 203 of the FPA or Commission authorization for blanket approval of market-based rates for generation services under section 205 of the FPA, filed "open access" transmission tariffs of general applicability.[FN52] The Commission applied its market rate analysis to IOUs, as well as IPPs, APPs, and marketers, and allowed IOUs to sell at market-based rates only if they opened their transmission systems to competitors.[FN53] The Commission also approved proposed mergers on the condition that the merging companies remedy anticompetitive effects potentially caused by the merger by filing "open access" tariffs. These early "open access" tariffs required only that the companies provide point-to-point transmission services, which is a much narrower requirement than that being imposed in this Rule and did not require transmission owners to provide to others the same quality of service that they themselves enjoyed.

Following PURPA, the economic and technological changes in the transmission and generation sectors helped give impetus to the many new entrants in the generating markets who could sell electric energy profitably with smaller scale technology at a lower price than many utilities selling from their existing generation facilities at rates reflecting cost. However, it became increasingly clear that the potential consumer benefits that could be derived from these technological advances could be realized only if more efficient generating plants could obtain access to the regional transmission grids. Because many traditional vertically integrated utilities still did not provide open access to third parties and still favored their own generation if and when they provided transmission access to third parties, barriers continued to exist to cheaper, more efficient generation sources.

D. The Energy Policy Act

In response to the competitive developments following PURPA, and the fact that PUHCA and lack of transmission access remained major barriers to new generators, Congress enacted Title VII of the Energy Policy Act of 1992 (Energy Policy Act). [FN54] A goal of the Energy Policy Act was to promote greater competition in bulk power markets by encouraging new generation entrants, known as exempt wholesale generators (EWGs), and by expanding the Commission's authority under sections 211 and 212 of the FPA to approve applications for transmission services.[FN55]

An EWG is defined as

Any person determined by the Federal Energy Regulatory Commission to be engaged directly, or indirectly through one or more affiliates as defined in [PUHCA] section 2(a)(11)(B), and exclusively in the business of owning or operating, or both owning and operating, all or part of one or more eligible facilities and selling electric energy at wholesale.[FN56]

If the Commission, upon an application, determines that a person is an EWG, that person will be exempt from PUHCA.[FN57] This provision removed a significant impediment to the development of IPPs and APPs by allowing them to develop projects as EWGs free from the strictures of PUHCA or the QF PURPA limitations.

While sections 211 and 212, as enacted by PURPA, were intended to provide greater access to the transmission grid, the limitations placed on these sections made them unusable in virtually all circumstances.[FN58] However, as amended by the Energy Policy Act, these sections now give the Commission broader authority to order transmitting utilities to provide wholesale transmission services, upon application, to any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale.

The Energy Policy Act also added section 213 to the FPA. Section 213(a) requires a transmitting utility that does not agree to provide wholesale transmission service in accordance with a good faith request to provide a written explanation of its proposed rates, terms, and conditions and its analysis of any ***21547** physical or other constraints.[FN59] Section 213(b) required the Commission to enact a rule requiring transmitting utilities to submit annual information concerning potentially available transmission capacity and known constraints.[FN60]

E. The Present Competitive Environment

Following the Energy Policy Act, the Commission established rules: (1) For certain generators to obtain EWG status and thus an exemption from PUHCA;[FN61] and (2) that required transmission information availability. The Commission also pursued a number of initiatives aimed at fostering the development of more competitive bulk power markets, including aggressive implementation of section 211, a new look at undue discrimination under the FPA, easing of market entry for sellers of generation from new facilities, and initiation of a number of industry-wide reforms. As stated by the Commission, in recognition of the Congressional goal in the Energy Policy Act of creating competitive bulk power markets:

Our goal is to facilitate the development of competitively priced generation supply options, and to ensure that wholesale purchasers of electric energy can reach alternative power suppliers and vice versa.[FN62]

1. Use of Sections 211 and 212 to Obtain Transmission Access

The Commission has aggressively implemented sections 211 and 212 of the FPA, as amended by the Energy Policy Act, in order to promote competitive markets.[FN63] When wheeling requests under sections 211 and 212 have been made, the Commission has required wheeling in almost all of the requests it has processed. To date, the Commission has issued orders (proposed or final) requiring wheeling in 12 of the 14 cases it has acted on.[FN64]

As a general matter, section 211 has permitted some inroads to be made by customers in obtaining transmission service from public utilities that historically have declined to provide access to their systems, or have offered service only on a discriminatory basis. Under section 211, the Commission has granted requests for the broader type of service that most utilities historically have refused to provide—network service. Although transmission owners have provided limited amounts of unbundled point-to-point transmission service, third-party customers have not been able to obtain the flexibility of service that transmission owners enjoy.

In Florida Municipal, a section 211 case, the Commission ordered "network," rather than the narrower "point-to-point," service.[FN65] Network service permits the applicant to fully integrate load and resources on an instantaneous basis in a manner similar to the transmission owner's integration of its own load and resources. At the same time, the Commission made the generic finding that the availability of transmission service will enhance competition in the market for power supplies and lead to lower costs for consumers. The Commission explained that as long as the transmitting utility is fully and fairly compensated and there is no unreasonable impairment of reliability, transmission service is in the public interest.[FN66]

As discussed infra, based on the mounting competitive pressures in the industry and rapidly evolving markets, we have concluded that section 211 alone is not enough to eliminate undue discrimination. The comments received on the proposed rules, discussed in detail infra, confirm this conclusion. The significant time delays involved in filing an individual service request for bilateral service under section 211 place the customer at a severe disadvantage compared to the transmission owner and can result in discriminatory treatment in the use of the transmission system. It is an inadequate procedural substitute for readily available service under a filed non-discriminatory open access tariff. As the Commission noted in Hermiston Generating Company, "[t]he ability to spend time and resources litigating the rates, terms and conditions of transmission access is not equivalent to an enforceable voluntary offer to provide comparable service under known rates, terms and conditions."[FN67]

2. Commission's Comparability Standard

In the Spring of 1994, the Commission began to address the problem of the disparity in transmission service that utilities provided to third parties in comparison to their own uses of the transmission system. In the seminal case in this area, American Electric Power Service Corporation (AEP), the company voluntarily proposed a tariff of general applicability that would offer firm, point-to-point transmission service for a minimum of one month.[FN68] The Commission accepted the proposed transmission tariff for filing and suspended its effectiveness for one day, subject to refund.[FN69] Rehearing requests challenged the Commission's summary approval of the restriction of service to point-to-point as being discriminatory and anticompetitive.[FN70] The rehearing ***21548** requests argued that the tariff should be expanded to include network services such as those used by the transmission owner. On rehearing, the Commission announced a new standard for evaluating claims of undue discrimination.

The Commission found that a voluntarily offered, new open access transmission tariff that did not provide for services comparable to those that the transmission owner provided itself was unduly discriminatory and anticompetitive.[FN71] In reaching that conclusion, the Commission broadened its undue discrimination analysis (which traditionally had focused on the rates, terms, and conditions faced by similarly situated third-party customers) to include a focus on the rates, terms, and conditions of a utility's own uses of the transmission system:

(A)n open access tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of its system.[FN72]

Refocusing the analysis was necessitated by the changing conditions in the electric utility industry, including the emergence of non-traditional suppliers and greater competition in bulk power markets. Because a transmission provider may use its system in different ways (e.g., to integrate load and resources when serving retail native load, to make off-system sales or purchases, or to serve wholesale requirements customers), the Commission set for hearing the factual issues associated with identifying those uses, as well as any potential impediments or consequences to providing comparable services to third parties.[FN73]

After AEP, the Commission applied this comparability standard to a proposed open access transmission tariff that was filed by Kansas City Power & Light Company (KCP&L) in support of a proposal to sell generation at market-based rates.[FN74] The Commission explained that, in light of AEP, the utility's proposed open access transmission tariff (which provided only for point-to-point service) did not adequately mitigate its transmission market power so as to justify allowing the requested market-based rates. KCP&L could charge market-based rates for sales only if it modified its proposed transmission tariff to reflect the AEP comparability standard.

Since then, the Commission has required comparable service in a variety of contexts, and has set for hearing the factual issues associated with comparable service. For example, the Commission found that market power can be adequately mitigated only if a merged company offers transmission services in accordance with the AEP comparability standard.[FN75] The Commission further held that, even if a merger does not result in an increase in market power, the merger would not be consistent with the public interest under section 203 of the FPA unless the merged company offers comparable transmission services, as defined in AEP.[FN76] The Commission therefore announced a transmission comparability requirement for all new mergers:

Given the transition of the electric utility industry as a whole, we conclude that, absent other compelling public interest considerations, coordination in the public interest can best be secured only if merging utilities offer comparable transmission services.[FN77]

In Heartland Energy Services, Inc.,[FN78] the Commission applied its comparability standard to an affiliated electric power marketer seeking blanket authorization to sell electricity at market-based rates. The Commission explained that

For all future cases involving blanket approval of market-based rates an offer of comparable transmission services will be required before the Commission will be able to find that transmission market power has been adequately mitigated. In the context of an affiliated power marketer, this means that all of its affiliated utilities must have a comparable transmission tariff on file.[FN79]

The Commission also denied a request by a company affiliated with a transmission-owning utility seeking permission to sell power at market-based rates to a particular customer. The denial was without prejudice to refiling such a request in a new section 205 proceeding, but only after the affiliated transmission-owning utility filed a comparable transmission service tariff.[FN80] The Commission added that it

Will require comparability in any situation in which a seller seeking market-based rates is affiliated with an owner or controller of transmission facilities.[FN81]

The Commission has also stated that “it will henceforth apply the transmission comparability standard announced in the AEP case to all transmitting utility members of an RTG.”[FN82]

The Commission further declared that comparable services must be provided through “open access” tariffs rather than only on a contract-by-contract basis:

(T)ariffs are essential to the provision of comparable services. Tariffs set out the services that are available and the terms and conditions under which those services will be made available * * *. (In contrast), a negotiation process creates uncertainty and imposes on customers delay and other transaction costs that the transmitting utility members of an RTG do not incur when using the transmission for their own benefit. Moreover, the ability to execute separate transmission agreements with different but similarly situated customers is the ability to unduly discriminate among them. A tariff ensures against such discrimination in the RTG.[FN83]

*21549 Thus, the Commission required the RTGs to amend their bylaws to commit all transmitting utility members to offer comparable transmission services to other RTG members pursuant to a transmission tariff or tariffs.

As discussed below, since the AEP comparability standard was announced, the Commission has set for hearing 44 open access tariffs to determine what constitutes comparable service. This number includes tariffs filed subsequent to the Open Access NOPR. All tariffs have now been made subject to the outcome of the Final Rule.

3. Lack of Market Power in New Generation

In 1994 in the KCP&L case, discussed in the prior section, the Commission continued to recognize that transmission remains a natural monopoly. However, it found that, in light of the industry and statutory changes that now allow ease of market entry, no wholesale seller of generation has market power in generation from new facilities.[FN84] In particular, the Commission explained that it had previously noted in Entergy Services, Inc. that

There was significant evidence that non-traditional power project developers, including qualifying facilities and independent power projects, are becoming viable competitors in long-run markets.[FN85]

The Commission further explained that since Entergy, Congress had enacted the Energy Policy Act, which had lowered barriers to the entry of new suppliers by creating a new class of power suppliers—EWGs—that are exempt from the provisions of PUHCA.[FN86] The Commission concluded that, in considering market-based rate proposals for generation sales, it need only focus on market power in transmission, generation market power in short-run markets, and other barriers to entry.[FN87]

4. Further Commission Action Addressing a More Competitive Electric Industry

To address the fact that the electric industry is becoming more competitive, and to remove barriers that might inhibit a more competitive industry, the Commission has initiated a number of proceedings: (1) Stranded Cost NOPR,[FN88] (2) Transmission Pricing Policy Statement,[FN89] (3) Pooling Notice of Inquiry,[FN90] (4) Regional Transmission Group (RTG) Policy Statement,[FN91] and (5) Notice of Inquiry on Merger Policy.[FN92]

In the Stranded Cost NOPR the Commission recognized that the trend toward greater transmission access and the transition to a fully competitive bulk power market could cause some utilities to incur stranded costs as wholesale requirements customers (or retail customers) use their supplier's transmission to purchase power elsewhere. As the Commission noted, a utility may have built facilities or entered into long-term fuel or purchased power supply contracts with the reasonable expectation that its customers would renew their contracts and would pay their share of long-term investments and other incurred costs. If the customer obtains another power supplier, the utility may have stranded costs. If the utility cannot locate an alternative buyer or somehow mitigate the stranded costs, the Commission explained that “the costs must be recovered from either the departing customer or the remaining customers or borne by the utility's shareholders.”[FN93] Accordingly, the Commission proposed to establish provisions concerning the recovery of wholesale and retail stranded costs by public utilities and transmitting utilities.

In the Transmission Pricing Policy Statement, the Commission announced a new policy providing greater flexibility in the pricing of transmission services provided by public utilities and transmitting utilities. The Commission traditionally had allowed only postage-stamp, contract-path pricing.[FN94] Under the new policy, we will permit a variety of proposals, including distance sensitive and flow-based pricing, which may be more suitable for competitive wholesale power markets.[FN95] The Commission explained that this “(g)reater pricing flexibility is appropriate in light of the significant competitive changes occurring in wholesale generation markets, and in light of our expanded wheeling authority under the Energy Policy Act of 1992.”[FN96] However, the Commission explained that any new transmission pricing proposal must meet the Commission's

AEP comparability standard. The Commission further explained that comparability of service applies to price as well as to terms and conditions.[FN97]

The Commission issued the Pooling Notice of Inquiry to receive comments on traditional power pools and on alternative power pooling institutions that are being explored in today's more competitive environment. The Commission expressed concern that

(G)iven the ongoing changes in the competitive environment of the electric utility industry—in particular, the potential for substantially increased access to transmission—we must consider whether we are appropriately balancing our dual objectives of promoting coordination and competition.[FN98]

Accordingly, the Commission explained that it wished to look at alternative power pooling institutions and to re-examine the role of more traditional power pools in today's environment of increased competition. In particular the Commission expressed its intent to ensure that its policies "are consistent with the development of a competitive bulk power market."[FN99]

In the RTG Policy Statement, the Commission announced a policy encouraging the development of RTGs. The Commission explained that a primary purpose of RTGs is to facilitate transmission access for potential users and voluntarily resolve disputes over such service. The Commission has approved the formation of three ***21550** RTGs.[FN100] One of the conditions is that each RTG member must offer comparable transmission services by tariff to other RTG members.

In the merger NOI, the Commission indicated that it will review whether its criteria and policy for evaluating mergers need to be modified in light of the changing circumstances occurring in the electric industry.

In addition to the Commission's actions, a number of states have initiated proceedings concerning retail wheeling or proposed legislation for retail wheeling, that is, for ultimate consumers to choose their supplier of power, or other restructuring proposals. [FN101]

5. Events Since Issuance of Open Access NOPR

Since issuance of the Open Access NOPR, public utilities have filed, in some form or another, 47 open access tariffs. In acting on those filings, the Commission has made all of the non-rate terms and conditions of those proposed tariffs subject to the outcome of this Final Rule.[FN102]

Over the last year, the Commission also has received and analyzed more than 20,000 pages of comments that were received from over 400 commenters, as well as additional information provided by industry participants at a number of Commission-initiated technical conferences.[FN103] Those technical conferences addressed several issues—ancillary services, pro forma tariffs, power pools, and ISOs—and provided significant input to the Commission's formulation of this Final Rule.

F. Need for Reform

The many changes discussed above have converged to create a situation in which new generating capacity can be built and operated at prices substantially lower than many utilities' embedded costs of generation. As discussed above, new generation facilities can produce power on the grid at a cost of less than 3 cents per kWh to 5 cents per kWh, yet the costs for large plants constructed and installed over the last decade were typically in the range of 4 to 7 cents per kWh for coal plants and 9 to 15 cents for nuclear plants.

Non-traditional generators are taking advantage of this opportunity to compete. Indeed, the non-traditional generators' share of total U.S. electricity generation increased from 4 percent in 1985 to 10 percent in 1993.[FN104] Much of this increased share of generation is the result of competitive bidding for new generation resources that has occurred in 37 states. Since 1984, almost 4,000 projects, representing over 400,000 MW, have been offered in response to requests. Over 350 projects have been selected to supply 20,000 MW, and, of these, 126 are now online producing almost 7,800 MW of power.[FN105]

In addition, the cost of utility-generated electricity differs widely across the major regions of the United States. Average utility rates range from 3 to 5 cents in the Northwest to 9 to 11 cents in California. Electricity consumers are demanding access to lower cost supplies available in other regions of the United States, and access to the newer, lower cost generation resources. Therefore, it is important that the non-traditional generators of cheaper power be able to gain access to the transmission grid on a non-discriminatory open access basis.

The Commission's goal is to ensure that customers have the benefits of competitively priced generation. However, we must do so without abandoning our traditional obligation to ensure that utilities have a fair opportunity to recover prudently incurred costs and that they maintain power supply reliability. As well, the benefits of competition should not come at the expense of other customers. The Commission believes that requiring utilities to provide non-discriminatory open access transmission tariffs, while simultaneously resolving the extremely difficult issue of recovery of transition costs (discussed infra), is the key to reconciling these competing demands.

Non-discriminatory open access to transmission services is critical to the full development of competitive wholesale generation markets and the lower consumer prices achievable through such competition.[FN106] Transmitting utilities own the transportation system over which bulk power competition occurs and transmission service continues to be a natural monopoly. Denials of access (whether they are blatant or subtle), and the potential for future denials of access, require the Commission to revisit and reform its regulation of transmission in interstate commerce. As discussed in detail in Section IV.B., such action is required by the FPA's mandate that the Commission remedy undue discrimination.

Since the time the NOPR issued, the Commission staff has completed an FEIS that provides a quantitative estimate of some of the cost savings expected from this Rule: approximately $3.8 to $5.4 billion per year. Other non-quantifiable benefits are also expected from this Rule and include: (1) Better use of existing assets and institutions; (2) new market mechanisms; (3) technical innovation; and (4) less rate distortion. These potential benefits to the Nation's electricity consumers and the economy as a whole confirm the need to take generic action to remove barriers to competition. In what follows, we set out the changes necessary to remedy undue discrimination and to ensure a fair transition to a more competitive regulatory regime.

IV. Discussion

A. Scope of the Rule

1. Introduction

The Commission has determined that non-discriminatory open access transmission services (including access to transmission information) and stranded cost recovery are the most critical components of a successful transition to competitive wholesale electricity markets. These issues are the focal point of this Rule, the accompanying rule on open access same-time information systems, and the accompanying proposed rule on capacity reservation tariffs.

***21551** In undertaking these initiatives, however, we are mindful that they are part of a broader picture of evolving issues affecting the electric industry and that other Commission policies will play an important role in ensuring the full development of competitive markets. Among the many issues that are important to competitive bulk power markets are: independent system operators (ISOs); regional transmission groups; generation market power; utility merger policy; and the development of innovative transmission pricing alternatives, such as flow-based, distance-sensitive transmission pricing methodologies that reflect incremental costs. In particular, we believe that ISOs have great potential to assist us and the industry to help provide regional efficiencies, to facilitate economically efficient pricing, and, especially in the context of power pools, to remedy undue discrimination and mitigate market power. Although we discuss some of these issues in this Rule, we will further develop our policies in other proceedings as well to accommodate and encourage more efficient market structures.

We now address the comments received on the scope of the proposed rulemaking.

2. Functional Unbundling

In the NOPR, the Commission preliminarily found that functional unbundling of wholesale generation and transmission services is necessary to implement non-discriminatory open access transmission.[FN107] At the same time, the Commission explained that the proposed rule would accommodate, but not require, corporate unbundling (which could include selling generation or transmission assets to a non-affiliate (divestiture) or the less aggressive step of establishing separate corporate affiliates to manage a utility's transmission and generation assets). However, we invited comments on functional unbundling and asked whether it is a strong enough measure to ensure non-discriminatory open access transmission without some form of corporate restructuring.

Comments

Commenters take both sides on whether functional unbundling is sufficient to assure non-discriminatory open access transmission or whether a stronger measure, such as corporate unbundling, is needed.

Supporting Functional Unbundling

Various commenters, including utilities and state commissions, generally support functional unbundling as sufficient to assure non-discriminatory open access transmission and oppose requiring corporate unbundling or divestiture.[FN108] Several commenters state that functional unbundling will remedy discrimination without creating the inefficiencies and additional costs that corporate restructuring would create.[FN109]

A number of other commenters argue that the Commission has no authority under the FPA to require divestiture of transmission assets.[FN110] Several of these commenters assert that, even if the Commission has the authority, the electric industry, unlike the natural gas industry, is not ready for mandated corporate unbundling because electric utilities still serve a high percentage of retail customers and own large amounts of the generating capacity. They assert that transmission system operation requires the operator to have control over much of the generating capacity.

Various other commenters also support functional unbundling, but believe that safeguards are needed to make it work.[FN111] Power Marketing Association, for example, suggests a number of safeguards: adoption of cost allocation mechanisms to ensure that utilities do not shift costs from generation to transmission; random audits of utility books; a requirement that each utility file a code of conduct that provides for maximum separation of generation and transmission functions; and active oversight and complaint procedures with strong penalties for abuse. OK Com and GA Com believe that functional unbundling along with the safeguard of the Commission's complaint process will provide sufficient incentive for non-discriminatory open access transmission.

Supporting Corporate Unbundling

A number of commenters see weaknesses in functional unbundling and argue that some form of corporate unbundling is necessary to assure non-discriminatory open access transmission.[FN112] American Forest & Paper says that there is affiliate abuse in the gas industry and argues that the electric industry presents even more serious potential for abuse because it is still dominated by vertically integrated utilities.[FN113] UAMPS asserts that functional unbundling is insufficient because the utility will still favor itself on issues related to transmission planning, capital investment, and operation and maintenance and replacement costs.

NIEP argues that divestiture of generation assets from transmission and distribution is the preferred mechanism for mitigating market power. It further suggests that if corporate divestiture is not feasible the Commission should

Seek to achieve "virtual divestiture" by requiring that the utility generation function be separated from transmission and distribution functions in a separate corporate affiliate, or business unit, and that affiliate transaction rules be established to guard against possible abuses.[FN114]

It maintains that the Commission has broad authority to protect against undue discrimination and anticompetitive behavior and can order divestiture if such action is required to remedy such behavior.[FN115]

FTC and DOJ argue that operational unbundling, an example of which is the formation of an independent system operator (ISO), likely would be more effective than functional unbundling and less costly than industry-wide divestiture.[FN116] FTC describes operational unbundling as "structural institutional arrangements, short of divestiture, that would separate operation of the transmission grid and access to it from economic interests in generation." It gives as an example the California proposal under which utilities would continue to own transmission lines, but an independent system operator would have operational control. DOJ also suggests "a separate authority" to ***21552** manage the grid and access to the grid, joint ventures, and voluntary pooling arrangements. These commenters argue that operational unbundling would be easier to enforce than functional unbundling.

DOE states that separation of the control of transmission from vertically-integrated companies does not necessarily require a poolco or any particular market mechanism. It suggests the possibility of an ISO that is functionally separate from any buyer or seller of generation, but would not perform all the functions of a poolco.

United Illuminating supports "operational unbundling" that would either (1) eliminate vertical integration and divestiture of transmission assets, leading to the formation of a regional transmission company, or (2) develop a regional contractual approach to transmission services that eliminates the transmission owner's market power and fairly allocates support of the transmission facilities between native load and third-party users of the system.

Commission Conclusion

We conclude that functional unbundling of wholesale services is necessary to implement non-discriminatory open access transmission and that corporate unbundling should not now be required. As we explained in the NOPR, functional unbundling means three things:

(1) A public utility must take transmission services (including ancillary services) for all of its new wholesale sales and purchases of energy under the same tariff of general applicability as do others;

(2) A public utility must state separate rates for wholesale generation, transmission, and ancillary services;

(3) A public utility must rely on the same electronic information network that its transmission customers rely on to obtain information about its transmission system when buying or selling power.

We believe that these requirements are necessary to ensure that public utilities provide non-discriminatory service.[FN117] These requirements also will give public utilities an incentive to file fair and efficient rates, terms, and conditions, since they will be subject to those same rates, terms, and conditions.

However, we recognize that additional safeguards are necessary to protect against market power abuses. Functional unbundling will work only if a strong code of conduct (including a requirement to separate employees involved in transmission functions from those involved in wholesale power merchant functions) is in place. In the RINs NOPR, the Commission proposed a code of conduct that would apply to all public utility transmission providers. As the Commission explained,

[T]his code of conduct would require, among other matters, a separation of the utilities' transmission system operations and wholesale marketing functions, and would define permissible and impermissible contacts between employees that conduct wholesale generation marketing functions and employees that handle transmission system operations and reliability in the system control center or at other facilities or locations.[FN118]

Adoption of this code of conduct, discussed in detail in the accompanying final rule on OASIS,[FN119] is needed to ensure that the transmission owner's wholesale marketing personnel and the transmission customer's marketing personnel have comparable access to information about the transmission system.

As noted by OK Com and GA Com, a further safeguard—section 206—is available if a public utility seeks to circumvent the functional unbundling requirements. Under section 206, any person is free to file a complaint with the Commission detailing any alleged misbehavior on the part of the public utility or its affiliates concerning matters subject to our jurisdiction under the FPA. Similarly, the Commission may, on its own motion, initiate a proceeding to investigate the practices of the public utility and its affiliates.

We believe that functional unbundling, coupled with these safeguards, is a reasonable and workable means of assuring that non-discriminatory open access transmission occurs. In the absence of evidence that functional unbundling will not work, we are not prepared to adopt a more intrusive and potentially more costly mechanism—corporate unbundling—at this time.

Several commenters discuss the need to encourage or even to require ISOs in the context of functional unbundling. We believe that ISOs have the potential to provide significant benefits (e.g., to help provide regional efficiencies, to facilitate economically efficient pricing, and, especially in the context of power pools, to remedy undue discrimination and mitigate market power) and will further our goal of achieving a workably competitive market. As we learned at our technical conference on power pools, many utilities are examining ISOs and corporate unbundling in various shapes and forms, particularly in the context of power pools. We discuss ISOs extensively in our section on power pools where we believe they will have an important role to play. However, in the context of individual utility transactions, we believe that the less intrusive functional unbundling approach outlined above is all that we must require at this time. Nevertheless, we see many benefits in ISOs, and encourage utilities to consider ISOs as a tool to meet the demands of the competitive marketplace.

As a further precaution against discriminatory behavior, we will continue to monitor electricity markets to ensure that functional unbundling adequately protects transmission customers. At the same time, we will analyze all alternative proposals, including formation of ISOs, and, if it becomes apparent that functional unbundling is inadequate or unworkable in assuring non-discriminatory open access transmission, we will reevaluate our position and decide whether other mechanisms, such as ISOs, should be required.

Finally, while we are not now requiring any form of corporate unbundling, we again encourage utilities to explore whether corporate unbundling or other restructuring mechanisms may be appropriate in particular circumstances. Thus, we intend to accommodate other mechanisms that public utilities may submit, including voluntary corporate restructurings (e.g., ISOs, separate corporate divisions, divestiture, poolcos), to ensure that open access transmission occurs on a non-discriminatory basis. We also will continue to monitor—and stand ready to work with parties engaging in—innovative restructuring proposals occurring around the country.

3. Market-Based Rates

a. Market-Based Rates for New Generation

In the NOPR, the Commission proposed to codify its determination in Kansas City Power & Light Company[FN120] ***21553** that the generation dominance standard for market-based sales from new capacity be dropped.[FN121] The proposed new section 35.27 would provide:

Notwithstanding any other requirements, any public utility seeking authorization to engage in sales for resale of electric energy at market-based rates shall not be required to demonstrate any lack of market power in generation with respect to sales from capacity first placed in service on or after June 10, 1996.[FN122]

However, this proposal would not affect the Commission's continuing authority to look at whether an applicant and its affiliates could erect other barriers to entry and whether there may be affiliate abuse or reciprocal dealing.[FN123]

Comments

A number of commenters support the Commission's determination in KCP&L[FN124] and several of them explicitly support the Commission's proposed codification.[FN125] EEI asserts that more than 50 percent of new generation is from non-utility sources and that recent competitive solicitations for new capacity have been greatly over-subscribed. Entergy argues that there is no evidence in any proceeding thus far of a market power problem in long-run markets.

Other commenters, however, oppose codifying KCP&L.[FN126] They believe that market power in long-run markets exists for both new and old generation due to, for example, constraints on interface capabilities and unduly long notice periods for replacement of purchases. They argue that there is not enough of a distinction between new and old generation to treat them differently. TDU Systems also notes that the Commission in KCP&L did not take into account the differences between firm and non-firm bulk power. NIEP and ELCON conclude that the Commission erroneously found in KCP&L that no wholesale seller of generation has market power in generation from new facilities. NIEP asserts that in each service area there is usually only one wholesale buyer—the utility—who also is virtually always a wholesale seller of generation. Under these circumstances, NIEP argues that there cannot be arm's-length bargaining. Environmental Action complains that the Commission's proposal to codify KCP&L ignores significant factors that impede entry to generation markets, such as utility resistance to purchased power, state government-created barriers to non-utility generation, pancaking of rates under the contract path approach, sunk investment, and scale economies.

Commission Conclusion

In reviewing applications to sell at market-based rates, whether from new (unbuilt) capacity or existing capacity, we require that the seller (and each of its affiliates) must not have, or must have mitigated, market power in generation and transmission and not control other barriers to entry. In order to demonstrate the requisite absence or mitigation of transmission market power, a transmission-owning public utility seeking to sell at market-based rates must have on file with the Commission an open access transmission tariff for the provision of comparable service. In addition, the Commission considers whether there is evidence of affiliate abuse or reciprocal dealing.[FN127]

In KCP&L, we stated that "in light of industry and statutory changes which allow ease of market entry, we therefore will no longer require rate applicants to submit evidence of generation dominance in long-run bulk power markets."[FN128] We further explained that we had examined "generation dominance in many different cases over the years" and had "yet to find an instance of generation dominance in long-run bulk power markets."[FN129] Commenters have criticized our findings in KCP&L, but no commenter has provided any evidence of generation dominance in long-run bulk power markets. Moreover, we have seen no such evidence in any of the market-based rate cases we have considered since KCP&L. Based on the comments received, we will codify the Commission's determination in KCP&L that the generation dominance standard for market-based sales from new capacity should be dropped. Because the Commission's findings in KCP&L applied to long-run markets, we will revise proposed §35.27 to apply to sales from capacity for which construction has commenced on or after the effective date of this Rule.[FN130]

The Commission wishes to clarify that dropping the generation dominance standard for new capacity does not affect the demonstration that an applicant must make in order to qualify for market-based rates for sales from its existing generating capacity. In other words, the fact that an applicant need not demonstrate its lack of generation dominance with respect to new capacity cannot be used to "bootstrap" the authorization of market-based rates for its existing capacity. Moreover, our evaluation of market-based rates for existing capacity will include consideration of new capacity.

In addition, the fact that we are codifying KCP&L does not mean that we will ignore specific evidence presented by an intervenor that a seller requesting market-based rates for sales from new generation nevertheless possesses generation dominance. For example, if the evidence indicated that the new generator, due to its proximity to an existing transmission constraint, could significantly influence the ability to move power across the constraint, we would consider such evidence in determining whether to grant the applicant's request.[FN131] If such evidence is presented, the Commission will evaluate whether the evidence disproves the premise that the seller lacks generation dominance with respect to its new capacity.

If the applicant has existing generation, the sales from which are authorized to be made on a market basis, the Commission would consider whether the new generation (when added to the existing generation with market-based authority) results in the applicant having generation dominance. On the other hand, if the applicant has existing generation, the sales from which are subject to cost-of-service regulation, the Commission would not include this generation in its analysis of the applicant's request for market-based rates for its new generation. The question of whether or not the applicant lacks generation dominance with respect to its existing capacity is relevant only if, and when, the seller applies to the Commission for authority to make wholesale sales for its existing capacity at market-based rates.

If evidence regarding an applicant's generation dominance with respect to ***21554** its new capacity is submitted, the applicant would be required to provide a satisfactory rebuttal.

b. Market-Based Rates for Existing Generation

In the NOPR, the Commission explained that increased competition resulting from open access transmission may reduce or even eliminate generation-related market power in the short-run market (sales from existing capacity).[FN132] Because market power has been the primary concern of the Commission in analyzing requests for market-based rates for such sales, we sought comments on the effect of industry-wide non-discriminatory open access on our criteria for authorizing power sales at market-based rates. The Commission also sought comments on whether the generation dominance standard should be dropped for market-based sales from existing capacity.

Comments

Many commenters support, but many also oppose, market-based rates for existing generation without a case-specific analysis of generation dominance.

Supporting Market-Based Rates for Existing Generation

Many commenters (primarily IOUs and a number of state commissions) assert that existing generators will not possess market power after implementation of non-discriminatory open access transmission and that market-based rates should be permitted generically for sales from existing generation.[FN133]

EEI asserts that market power concerns generally would be transitory, limited to the time needed to build new facilities. Thus, it recommends that all markets be declared competitive by a date certain and that market-based rates then be allowed, with customers permitted to file complaints. Florida Power Corp believes that existing procedures under sections 205 and 206 will adequately protect consumers. Other commenters also urge the Commission to eliminate its generation dominance standard, but assert that the Commission should allow a showing of market dominance in a complaint or show cause proceeding.[FN134] CT DPUC notes that the Commission should be able to rely on rules of conduct, market mechanisms, and monitoring to curb any market power that may exist.

Utilities For Improved Transition argues that if utilities cannot get market-based rates, the new players in the market will have an unfair advantage, since they do not have to carry the traditional utilities' burden of older, less efficient plants.

Entergy proposes a screening test that would permit the Commission to "deregulate" wholesale sales to certain short-run markets. CINergy recommends that after industry-wide open access tariffs become effective, the Commission adopt a rebuttable presumption that all markets are workably competitive; that presumption could be rebutted in a section 206 proceeding.[FN135]

UtiliCorp, while it believes that market power will probably be fully mitigated by open access, also argues that the Commission should examine generation dominance on a region-by-region basis.[FN136] Montana-Dakota Utilities argues that the Commission should allow all suppliers in a power pool or RTG to have market-based rates after a Commission finding that there is sufficient generation competition within the region.

Duke states that it would be highly inconsistent for the Commission to require open access, but not allow utilities to compete in the market. It further states that the relevant market should be determined using standard antitrust techniques; the Commission should examine the options available to customers and determine whether the utility possesses monopoly power in a relevant market.

Opposing Market-Based Rates for Existing Generation

Many commenters are concerned that even with open access tariffs certain generators will be able to exercise market dominance.[FN137] For example, NARUC argues that utilities retain market power through their ownership of existing generation and transmission facilities, favorable long-term contracts for fuel and other inputs, and access to superior generation sites.[FN138] NRECA believes that the universe of generation providers is still too narrow to assume a competitive market and that other factors, such as transmission constraints and pancaking of rates, will inhibit the development of competitive markets.[FN139] FTC says that, although comparable transmission access could broaden the relevant geographic market for generation, the Commission should not assume that there will be no market power. It says that the Commission must continue to evaluate each case.[FN140] TDU Systems argues that the Commission cannot move to market-based rates without a Congressional determination that deregulation of wholesale electric rates should be implemented. It further asserts that the Commission does not have a factual basis for a reasoned conclusion that regulated utilities do not have market dominance—full open access is only a goal at this time, and the success of open access will depend upon the transmission rate structures the Commission approves.

LEPA raises concerns that the small bulk power suppliers, QFs, co-generators, EWGs, IPPs, and marketers (who provide non-requirements power) may not be able to bring competition to the wholesale market. LEPA concludes that "barriers will exist unless buyers have full access to requirements power itself, rather than just to the chance to acquire the individual components of requirements power."[FN141] TDU Systems raises concerns about the limited number of generation providers and the effect of possible future mergers. It also argues that pancaked rates raise the cost of transmission to third parties, thereby restricting the geographic scope of markets. As a result, TDU Systems asserts that individual generators in highly concentrated regions will still be able to exert market power. OH Com expresses concerns that restrictions on siting of generation and transmission will favor nearby generators. SC Public Service Authority argues that if the Commission allows utilities to recover stranded costs their market power will not be mitigated, since customers will ***21555** have to pay exit fees to switch suppliers.[FN142]

CCEM notes that in Order No. 636 gas pipelines were not allowed market-based rates for merchant sales until after transmission had been completely unbundled and non-discriminatory open access had been fully implemented.

DOE and DOJ assert that open access should not be assumed to mitigate market power sufficiently to justify deregulation of existing generation—structural changes, such as control of the regional grid by an independent entity, are required. DOE requests that the Commission continue to look for affiliate abuse when reviewing market-based rates for new generation. Similarly, EPA is concerned that even with open access, individual generators may still exert market power by their domination of a particular geographic market. It is also concerned that low-cost plants that are subject to weaker environmental standards could have a market advantage. NEPOOL Review Committee requests that the Commission not approve any market prices "where the market into which the seller proposes to sell is not effectively competitive due to the absence of regional transmission products and prices."[FN143]

Commission Conclusion

While the Commission expects this Rule to facilitate the development of competitive bulk power markets, we find that there is not enough evidence on the record to make a generic determination about whether market power may exist for sales from existing generation. We continue to have concerns about how to define the relevant markets and believe that a more rigorous analysis is needed than can be achieved with the limited market data that is now available. We will continue our case-by-case approach that allows market-based rates based on an analysis of generation market power in first tier and second tier markets. [FN144] In particular cases, however, the effect of the mandatory open access prescribed by this Final Rule may lead to the consideration of geographic markets for the applicant's generation products that are broader in scope than the first-tier and second-tier markets currently considered.[FN145] By the same token, in some cases, evidence of the effects of transmission constraints may circumscribe the scope of the relevant geographic market for the applicant's generation products.

While we will continue to apply the first-tier/second-tier analysis, we will allow applicants and intervenors to challenge the presumption implicit in the Commission's practice that the relevant geographic market is bounded by the second-tier utilities. Thus, for instance, applicants may present evidence that the relevant market is in fact broader than the first or second tier. In support of such a contention, an applicant would need to show more than the existence of open access. For example, an applicant might attempt to demonstrate the lack of significant transmission constraints in the more broadly defined market and that cumulative transmission rates would not significantly affect the ability of more distant suppliers to compete in the relevant market. Similarly, an intervenor may present evidence that, due to the existence of significant transmission constraints within the first- and second-tier markets, the relevant market is in fact more limited in scope.[FN146]

Finally, we will maintain our current practice of allowing market-based rates for existing generation to go into effect subject to refund. To the extent that either the applicant or intervenors in individual cases offer specific evidence that the relevant geographic market ought to be defined differently than under the existing test, we will examine such arguments through formal or paper hearings.

Because our goal is to develop more competitive bulk power markets, we will continue to monitor markets to assess the competitiveness of the market in existing generation, and we will modify our market rate criteria if and when appropriate. However, any changes we might make to our analysis for authorizing market-based rates in the future will not upset transactions entered into pursuant to existing market-based rate authority. The policies we put in place today to develop a smoothly functioning transmission access regime will provide useful experience and information for assessing the effects of generation concentration.

4. Merger Policy

In the NOPR, the Commission did not address possible ramifications of the NOPR with regard to its existing merger policy.

Comments

A number of commenters suggest that the Commission should reevaluate its merger policy in light of the NOPR.[FN147] They further suggest a number of changes that they believe need to be made to the Commission's existing merger policy.

Most commenters raising this issue express concerns that mergers will lessen competition and hinder achievement of competitive bulk power markets.[FN148] For example, NRECA indicates that the Commission's merger policy is at a crossroads. It believes that it is essential for the Commission to reevaluate its merger policy in concert with the proposed rulemakings.[FN149] Similarly, TAPS recommends that the Commission reevaluate its merger criteria to ensure that in a more competitive era, mergers are found to be consistent with the public interest only if they are pro-competitive. Several commenters argue that the Commission should continue to conduct a case-by-case investigation of the product and geographic markets that will be affected by a proposed merger.[FN150]

A number of commenters also suggest certain changes that they would like to see in the Commission's merger policy.[FN151] APPA recommends that, at a minimum, all merger approvals considered by the Commission should be conditioned on: (1) Filing an open access transmission tariff, (2) demonstrating no market power in generation or ancillary services, and (3) granting all existing requirements customers of the merged entity the right to convert existing contracts to rights to equivalent transmission capacity. Several commenters suggest adopting the U.S. Department of Justice Merger ***21556** Guidelines in analyzing merger proposals.[FN152]

Environmental Action and others contend that merging utilities must be required to demonstrate real net benefits to retail and wholesale customers that could not otherwise be achieved but for the proposed merger.[FN153]

Commenters also argue that the Commission should use its merger conditioning authority to order divestiture of transmission and generation when required to ensure competition.[FN154] Environmental Action and NEPOOL Review Committee suggest conditioning merger applications on the existence of regional transmission pricing arrangements to mitigate any generation market power gained by the merging entities.

Commission Conclusion

The Commission appreciates the concerns and suggestions raised with respect to our merger policy. However, since the time the NOPR was issued (and comments received thereon), we issued a Notice of Inquiry on the Commission's merger policy in Docket No. RM96-6-000.[FN155] There we indicated that we will review whether our criteria and policies for evaluating mergers need to be modified in light of the changing circumstances, including this final rule, that are occurring in the electric industry. The NOI proceeding will permit us to consider comments from all interested participants and, at the same time, allow us to review our merger criteria and policies in light of this final rule. We are committed to reviewing our merger policy in a timely manner in the ongoing NOI proceeding.[FN156]

5. Contract Reform

In the NOPR, the Commission explained that it believed that it could remedy unduly discriminatory practices and achieve more competitive bulk power markets without abrogating existing wholesale power supply contracts that bundle generation and transmission services and existing wholesale transmission contracts.[FN157] Thus, we proposed to apply the functional unbundling requirement only to transmission services under new requirements contracts, new coordination contracts, and new transactions under existing coordination contracts. However, the Commission did invite comment on whether it would be contrary to the public interest to allow all or some of the above types of existing contracts to remain in effect.

Comments

Requirements and Transmission Contracts

Many of the commenters (including utility customers and third-party power suppliers) addressing this issue oppose abrogating existing contracts on a generic basis.[FN158] A number of the commenters contend that existing contracts should be retained because they are the result of mutually beneficial bargaining.[FN159] SMUD and TANC are concerned that existing contracts providing for transmission service that is superior to the pro forma tariffs not be abrogated.[FN160] Ohio Edison argues that existing contracts have contributed to the emergence of competition, meet the specific needs of the parties, have been approved by the Commission, and have not been found to be unduly discriminatory or violative of the public interest, and that their preservation is consistent with the Energy Policy Act, most notably amended section 211 of the FPA. PacifiCorp and AEP express concern that contract abrogation would create competitive instability. American Forest & Paper argues that the Commission cannot refuse to honor existing contracts if it expects a competitive bulk power market to emerge.

Numerous commenters further argue that contract abrogation requires a fact-based, contract-specific evaluation, and they oppose any generic declaration that existing contracts are contrary to the public interest.[FN161] Some suggest that generic contract abrogation cannot be justified under the public interest standard.[FN162]

Missouri Basin MPA argues that the Commission should allow abrogation of existing wholesale power and transmission arrangements if the customer can demonstrate the undue competitive disadvantage caused by the arrangement.

A few commenters support some form of generic contract abrogation.[FN163] CCEM asserts that existing wholesale requirements customers must be given the right to convert to transmission service under non-discriminatory open access tariffs.[FN164] CCEM notes that this is the same relief from undue discrimination that the Commission afforded to pipeline customers in Order Nos. 436 and 500.[FN165] CCEM emphasizes that here, in contrast to what occurred in the gas industry, "[c]onversion rights should be understood as the logical quid pro quo for introducing extra-contractual stranded-cost recovery rights into the wholesale requirements contracts of electric utilities." [FN166] NRECA asserts that it would be unduly discriminatory to allow new transmission customers to use the open access transmission tariffs, but not allow existing customers the same access.[FN167]

TAPS says that if those who now have discriminatory contracts are forced to live with those contracts, a fully competitive market will be delayed considerably.[FN168] Moreover, TAPS argues, the Commission has a statutory duty to remedy the undue discrimination that it is only now recognizing. Even if the Commission will not abrogate these contracts across the board, TAPS asserts that we should use our section 206 authority to do so on a contract-by-contract basis.

San Francisco requests that the Commission clarify that a holder of capacity rights under an existing ***21557** contract can extend contractual rights to transmission access at least coterminous with the life of the project and under a roll-over or renewal contract on the same basis as provided in the existing contract. Anoka EC proposes that when a wholesale purchaser's contract expires, it should have a right of first refusal to contract for the transmission capacity to which it previously had a right. Knoxville urges the Commission to require renegotiation of the notice and/or term of all existing contracts for which the voluntary termination period exceeds the time frame for implementation of the final rule.

NEPCO suggests that we require existing power contracts that allow rate changes to be separated into their generation and transmission components, without otherwise disturbing their terms; this would allow comparisons between the transmission service the utility provides to its power customers and the service it offers to others.[FN169]

Coordination Agreements

CINergy argues that coordination agreements should not be excluded from the comparability standard and that the Commission should use its authority under section 206 to require amendments to such agreements, just as it did in Order 636 in requiring unbundling of pipeline supply contracts. CINergy suggests that public utilities should be given up to three years to file the amendments to avoid hardship on the industry and the Commission's staff. CINergy further asserts that future transactions conducted under coordination agreements should be unbundled and the transmission component subjected to the comparable transmission service requirement.

Others argue that purchases under existing coordination agreements made on behalf of retail native load should not be unbundled.[FN170] NY Com and IL Com recommend that proposed §35.28(c) be modified to state that the functional unbundling requirement "exclude(s) those wholesale purchases made by the utility to serve existing or expected native retail load."

Utilities For Improved Transition disagrees with the idea that new transactions under existing coordination agreements should be subject to the rule.[FN171] It argues that the sanctity of coordination contracts should be the same as for other contracts. Coordination contracts are not simply agreements to agree in the future, according to Utilities For Improved Transition; they set forth terms and rates and merely leave the timing of transactions to be resolved in the future. Moreover, it argues that the Commission has given no reason to abandon its practice of encouraging coordination sales by allowing price flexibility.

Commission Conclusion

Requirements and Transmission Contracts

We do not believe it is appropriate to order generic abrogation of existing requirements and transmission contracts. While the Commission did generically find it appropriate to modify natural gas contracts to complete the move to a competitive commodity market in natural gas, we face a different situation here. At the time the Commission addressed this situation in the natural gas industry, it was faced with shrinking natural gas markets, statutory escalations in natural gas ceiling prices under the Natural Gas Policy Act, and increased production of gas.[FN172] In other words, there was a market failure in the industry that required the extraordinary measure of generically allowing all customers to break their contracts with pipelines.

In contrast, there is no such market failure in the electric industry. Although changes in the industry have been and continue to be dramatic, we do not believe they compel generic abrogation of requirements and transmission contracts.[FN173]

While we have concluded that current conditions in the wholesale power market do not warrant the generic modification of requirements contracts, we conclude nonetheless that the modification of certain requirements contracts on a case-by-case basis may be appropriate. We conclude further that, even if customers under such contracts are bound by so-called Mobile-Sierra clauses, they nonetheless ought to have the opportunity to demonstrate that their contracts no longer are just and reasonable.

The Commission finds that it would be against the public interest to permit a Mobile-Sierra clause in an existing wholesale requirements contract to preclude the parties to such a contract from the opportunity to realize the benefits of the competitive wholesale power markets. For purposes of this finding, the Commission defines existing requirements contracts as contracts executed on or before July 11, 1994.[FN174] By operation of this finding, a party to a requirements contract containing a Mobile-Sierra clause no longer will have the burden of establishing independently that it is in the public interest to permit the modification of such contract. The party, however, still will have the burden of establishing that such contract no longer is just and reasonable and therefore ought to be modified.

This finding complements the Commission's finding that, notwithstanding a Mobile-Sierra clause in an existing requirements contract, it is in the public interest to permit amendments to add stranded cost provisions to such contracts if the public utility proposing the amendment can meet the evidentiary requirements of this Rule.[FN175] The Commission's complementary Mobile-Sierra findings are not mutually exclusive. Any contract modification approved under this Section shall provide for the utility's recovery of any costs stranded consistent with the contract modification. The stranded costs must be prudently incurred, legitimate and verifiable, as provided in Section IV.J. Further, the Commission has concluded that if a customer is permitted to argue for modification of existing contracts that are less favorable to it than other generation alternatives, then the utility should be able to seek modification of contracts that may be beneficial to the customer.

The Commission believes that the most productive way to analyze contract modification issues is to consider simultaneously both the selling public utility's claims, if any, that it had a reasonable expectation of continuing to serve the customer beyond the term of the contract and the customer's claim, if any, that the contract no longer is just and reasonable and therefore ought to be modified. Thus, if the selling public utility intends to claim stranded costs, it must present that claim in any section 206 proceeding brought by the customer to shorten or terminate the contract. Similarly, if the customer intends to claim that the notice or termination provision of its existing requirements contract is unjust and unreasonable, it must present that claim in any proceeding brought by the selling public utility to seek recovery of stranded ***21558** costs. This will promote administrative efficiency and will permit the Commission to consider how the contracting parties' claims bear on one another.

The Commission does not take contract modification lightly. Whether a utility is seeking a contract amendment to permit stranded cost recovery based on expectations beyond the stated term of the contract, or a customer is seeking to shorten or eliminate the term of an existing contract, we believe that each has a heavy burden in demonstrating that the contract ought to be modified. Still, we believe that given the industry circumstances now facing us, both selling utilities and their customers ought to have an opportunity to make the case that their existing requirements contracts ought to be modified. By providing both buyers and sellers this opportunity, the Commission attempts to strike a reasonable balance of the interests of all market participants. The Commission expects that many of the arguments presented by buyers and sellers in such proceedings will be fact specific.

We note that because we are not abrogating existing requirements and transmission contracts generically and because the functional unbundling requirement of the Final Rule applies only to new wholesale services, the terms and conditions of the Final Rule pro forma tariff do not apply to service under existing requirements contracts. However, if a customer's existing bundled service (transmission and generation) contract or transmission-only contract expires, and the customer takes any new transmission service from its former supplier, the terms and conditions of the Final Rule tariff would then apply to the transmission service that the customer receives.

A further issue concerning firm contract customers is their right to transmission capacity (and the rate for such capacity) when their contracts expire by their own terms or become subject to renewal or rollover. We have concluded that all firm transmission customers (requirements and transmission-only), upon the expiration of their contracts or at the time their contracts become subject to renewal or rollover, should have the right to continue to take transmission service from their existing transmission provider. The limitations are that the underlying contract must have been for a term of one-year or more and the existing customer must agree to match the rate offered by another potential customer, up to the transmission provider's maximum filed transmission rate at that time, and to accept a contract term at least as long as that offered by the potential customer.[FN176] This means that there is no right to grandfather the historical price of the transmission service. Thus, if not enough capacity is available to meet all requests for service, the right of first refusal gives the capacity to the existing customer who had contractually been using the capacity on a long-term, firm basis, assuming that it meets the conditions set forth above. Moreover, this limited right of first refusal is not a one-time right of first refusal for contracts existing as of the date of the final rule, but is an ongoing right that may be exercised at the end of all firm contract (including all future unbundled transmission contracts) terms. A customer converting existing bundled service to the Final Rule pro forma tariff would not have a reservation priority for capacity expansions, unless the existing contract provides for future transmission to the customer that requires capacity expansion.[FN177]

Finally, with respect to all existing requirements contracts and tariffs that provide for bundled rates, we will require all public utilities to make informational filings setting forth the unbundled power and transmission rates reflected in those contracts and tariffs These informational rates must be submitted to the Commission within 60 days of publication of the Final Rule in the Federal Register and must also be included as a line item on all bills submitted to wholesale customers in the third month following the effective date of this final rule. The unbundled informational rates will permit wholesale customers to compare rates in anticipation of their contracts expiring so that they can evaluate alternative contracts.

Coordination Agreements

The situation as to coordination agreements requires a slightly different approach.[FN178] While we also believe that as a general matter it is important not to generically abrogate any coordination agreements, this is particularly true for non-economy energy coordination agreements that may reflect complementary long-term obligations among the parties. This type of agreement presents special problems and, as discussed below, we will not generically require this type of coordination agreement to be modified.[FN179]

Hundreds of coordination agreements exist in the industry today. Many are open-ended agreements that permit new transactions to occur well into the future. Because these contracts may not expire of their own terms in a reasonable time, they may present a larger and more enduring obstacle to non-discriminatory open access and more competitive bulk power markets. Thus, to assure that non-discriminatory open access becomes a reality in the relatively near future, we will partially modify existing economy energy coordination agreements. We will condition future sales and purchase transactions under existing economy energy coordination agreements[FN180] to require that the transmission service associated with those transactions be provided pursuant to this Rule's requirements of non-discriminatory open access, no later than December 31, 1996.[FN181] We also will require that for new economy energy coordination agreements[FN182] where the transmission owner uses its transmission system to make economy energy sales or purchases, the transmission owner must take such service under its own transmission tariff as of the date trading begins under the agreement.[FN183]

***21559** Finally, we will treat non-economy energy coordination agreements differently. We will not require their modification. However, this does not insulate such agreements from complaints that transmission service provided under such agreements be provided pursuant to the Final Rule pro forma tariff.

With respect to coordination pricing practices, we conclude that non-discriminatory open access consistent with the requirements of this Rule is necessary if we are to allow utilities to continue to use market-driven pricing, such as split-the-savings pricing, for coordination sales. Absent such non-discriminatory open access, a utility would be able to deny access to others so as to obtain a higher price for its own power sales.

6. Flow-Based Contracting and Pricing

In the NOPR, the Commission discussed the procedures to be used in establishing Stage One rates. These Stage One rates were proposed as an administrative convenience. The proposal merely followed the long-established practice of establishing rates on the basis of contract path pricing.[FN184] The Commission made no determination with respect to the appropriateness of flow-based pricing or contracting for other purposes.[FN185]

Comments

Most of the commenters addressing this issue recommend that industry or the Commission—either in this rule or ultimately—dispense with the traditional contract path basis for pricing and contracting. Most commenters also recommend that the Commission adopt or encourage a regional approach to the solution of transmission pricing problems, though they differ markedly in how to account for flows.[FN186]

Transmission customers generally seek to rid themselves of "pancaked" transmission rates that are associated with the traditional approach to transmission pricing.[FN187] They propose the development of regionwide transmission rates, perhaps determined on a pool or RTG basis. Most, however, do not discuss how to account for unscheduled flows.[FN188]

Many transmission providers, some regulatory authorities, and some individuals strongly support flow-based pricing. Most of these commenters recognize a need for a regional approach to resolve transmission pricing concerns.[FN189] However, many of them also appear to accept contract pricing in the near term because of the need to implement open access quickly.[FN190] NERC recommends that the Commission maintain an open position on the transfer scheduling process and supports changes in the process to reflect actual power flows. EEI suggests that the Commission should be willing to deviate from a contract path approach, since competition may be accompanied by greater unscheduled flows and contract pricing is not well equipped to deal with such flows. However, EEI concludes that a single approach to pricing will not be appropriate for all systems.

Other commenters, however, do raise concerns with respect to flow-based pricing. AEC & SMEPA considers flow-based pricing to be flawed because that method makes an individual customer responsible for load flow effects caused by a third party's development of the third-party's transmission system over which the customer and its transmission provider had no control. Dayton P&L fears that competition would be lessened under flow-based pricing because utilities with large transmission systems would dominate the market.

Several commenters oppose Southern's and United Illuminating's flow-based proposals, arguing that the methodologies are based on estimates of actual flows or a set of conditions with limited applicability. Various commenters also believe that a single rate is flawed and could cause just as many problems as contract path pricing.[FN191]

Most commenters appear to believe that the Commission endorsed contract path pricing in the NOPR. Hogan expresses concern that many industry participants' understanding of the pro forma tariffs is based on the fiction of the contract path. The MT Dept of Environmental Quality believes that despite the Commission's pledge to consider innovative pricing proposals,[FN192] such proposals will receive heavy scrutiny, while conventional contract path pricing proposals will receive nearly automatic approval. Dominion is concerned that relying on the initiative of individual transmission owners to develop flow-based pricing will yield slow and patchy results.

Commission Conclusion

We will not, at this time, require that flow-based pricing and contracting be used in the electric industry. In reaching this conclusion, we recognize that there may be difficulties in using a traditional contract path approach in a non-discriminatory open access transmission environment, as described by Hogan and others. At the same time, however, contract path pricing and contracting is the longstanding approach used in the electric industry and it is the approach familiar to all participants in the industry. To require now a dramatic overhaul of the traditional approach—such as a shift to some form of flow-based pricing and contracting—could severely slow, if not derailed for some time, the move to open access and more competitive wholesale bulk power markets. In addition, we believe it is premature for the Commission to impose generically a new pricing regime without the benefit of any experience with such pricing. We welcome new and innovative proposals, but we will not impose them in this Rule.

While we are not requiring the use of any form of flow-based pricing, we recognize that some versions of flow-based pricing could have benefits. For example, some versions of flow-based pricing could more accurately reflect and price the actual power flows on transmission systems and thus could produce efficiency gains, better generation siting decisions, and benefits for customers and utilities alike. Other versions could more accurately assign capacity rights in accordance with a party's contribution to capacity costs.

These potential benefits, however, will not simply come about in the abstract. Flow-based pricing methodologies that will achieve the benefits sought by most of the ***21560** participants in the industry are in a development stage and require further work and refinement to address some of the difficulties associated with flow-based approaches. Concurrent work on OASIS and resolving available transmission capability issues may help resolve flow-based issues. However, as demonstrated by the paucity of possible methodologies presented in the comments, developing workable methodologies will be difficult. As we explained in our Transmission Pricing Policy Statement, we are receptive to proposals for alternative rate methodologies, such as distance-sensitive and flow-based pricing, as long as the proposals are well supported. However, we have yet to receive a formal rate application for a flow-based pricing methodology that has been tested enough that it can be required on a generic basis. Thus, we have decided to go forward to achieve open access and more competitive wholesale bulk power markets without waiting for the development of a generic flow-based pricing methodology.

We wish to emphasize further that in taking this approach we are not endorsing the traditional contract path approach as the only available approach. We continue to approve contract path pricing because it is the long-established pricing method that comes to us in rate filings by the electric industry, is administratively convenient and feasible, and thus is a practical way to move forward now. We remain open to alternative methodologies, but need to see better developed approaches from the industry before we can consider generic adoption of alternative pricing.

We also believe the adoption of flow-based pricing will be more practical on a regional, instead of individual utility, basis. Some forms of flow-based pricing may even require a regional approach. To this extent, regional ISOs could be a valuable mechanism for implementing such pricing reforms.

B. Legal Authority

The Commission reaffirms its conclusion in the NOPR that we have the authority under the FPA to order wholesale transmission services in interstate commerce to remedy undue discrimination by public utilities. We analyze below the relevant cases examining our wheeling authority, then discuss and respond to the legal arguments raised by the commenters.

1. Bases for Legal Authority

a. Undue Discrimination/Anticompetitive Effects

In upholding the Commission's order requiring non-discriminatory open access in the natural gas industry, the court in Associated Gas Distributors v. FERC stated that the Natural Gas Act "fairly bristles" with concern for undue discrimination. [FN193] The same is true of the FPA. The Commission has a mandate under sections 205 and 206 of the FPA to ensure that, with respect to any transmission in interstate commerce or any sale of electric energy for resale in interstate commerce by a public utility, no person is subject to any undue prejudice or disadvantage. We must determine whether any rule, regulation, practice or contract affecting rates for such transmission or sale for resale is unduly discriminatory or preferential, and must prevent those contracts and practices that do not meet this standard. As discussed below, AGD demonstrates that our remedial power is very broad and includes the ability to order industry-wide non-discriminatory open access[FN194] as a remedy for undue discrimination. The AGD court reached this decision even in the face of prior cases that acknowledged that Congress did not mandate common carriage or explicitly empower the Commission to order direct access for either gas transporters or electric utilities. Moreover, the Commission's power under the FPA "clearly carries with it the responsibility to consider, in appropriate circumstances, the anticompetitive effects of regulated aspects of interstate utility operations pursuant to (FPA) sections 202 and 203, and under like directives contained in sections 205, 206, and 207."[FN195]

Therefore, based on the mandates of sections 205 and 206 of the FPA and the case law interpreting the Commission's authority over transmission in interstate commerce, we conclude that we have ample legal authority—indeed, a responsibility—under section 206 of the FPA to order the filing of non-discriminatory open access transmission tariffs if we find such order necessary as a remedy for undue discrimination or anticompetitive effects.[FN196] We discuss below the primary court decisions that touch on our wheeling authority under sections 205 and 206.

The Commission's authority to order access as a remedy for undue discrimination under the Natural Gas Act (NGA) was upheld and discussed in detail in AGD. In AGD, the court upheld in relevant part the Commission's Order No. 436.[FN197] That order found the prevailing natural gas company practices to be "unduly discriminatory" within the meaning of section 5 of the NGA (the parallel to section 206 of the FPA) and held that if pipelines wanted blanket certification for their transportation services, they must commit to transport gas for others on a non-discriminatory basis; in other words, they must provide non-discriminatory open access.

In upholding the Commission's authority to require open access, the court first noted that the opponents' arguments against such authority must proceed "uphill." The statute contains no language forbidding the Commission to impose common carrier status on pipelines, let alone forbidding the Commission to impose "a specific duty that happens to be a typical or even core component of such status." The court found that the legislative history cited by the opponents came nowhere near overcoming this statutory silence. Rather, the legislative history supported only the proposition that Congress itself declined to impose common carrier status.[FN198] Emphasizing Congress' deep concern with undue discrimination, the court found that the Commission had ample authority to "stamp out" such discrimination:

The issue seems to come down to this: Although Congress explicitly gave the Commission the power and the duty to achieve one of the prime goals of common carriage regulation (the eradication of undue discrimination), the Commission's attempted exercise of that power is invalid because Congress in 1906 and 1914 and 1935 and 1938 itself refrained from affixing common carrier status directly onto the pipelines and from authorizing the Commission to do so. ***21561** And this proposition is said to control no matter how sound the Order may be as a response to the facts before the Commission. We think this turns statutory construction upside down, letting the failure to grant a general power prevail over the affirmative grant of a specific one.[FN199]

The AGD court found that court decisions under the FPA did not support the view that the Commission's authority to "stamp out" undue discrimination is hamstrung by an inability to require non-discriminatory open access as a remedy. These decisions are discussed below.
One of the earliest cases on wheeling is Otter Tail Power Company v. United States (Otter Tail).[FN200] In that case, the Supreme Court rejected the argument that the District Court, in a civil antitrust suit, could not order wheeling because to do so would conflict with the FPC's purported wheeling authority.[FN201] The Court explained that Congress had decided not to impose a common carrier obligation on the electric power industry and noted that the Commission was not at that time expressly granted power to order wheeling.[FN202] In effect, it concluded that because Congress did not include common carrier provisions in the FPA, the Commission must not have any express authority to order wheeling that would preclude the District Court from imposing a wheeling remedy. Nowhere, however, did the Court say that the Commission lacked authority under section 206 to remedy undue discrimination. Indeed, that was simply not a matter before the Court or of any consequence to its decision.

In the FPA, while Congress elected not to impose common carrier status on the electric power industry, it tempered that determination by explicitly providing the Commission with the authority to eradicate undue discrimination—one of the goals of common carriage regulation.[FN203] By providing this broad authority to the Commission, it assured itself that in preserving "the voluntary action of the utilities" it was not allowing this voluntary action to be unfettered. It would be far-reaching indeed to conclude that Otter Tail, which was a civil antitrust suit that raised issues entirely unrelated to our authority under section 206, is an impediment to our achieving one of the primary goals of the FPA—eradicating undue discrimination in transmission in interstate commerce in the electric power industry.

In Richmond Power & Light Company v. FERC (Richmond),[FN204] the FPC, in reaction to the 1973 oil embargo, was attempting to reduce dependence on oil. The FPC requested that utilities with excess capacity wheel power to the New England Power Pool (NEPOOL). In response, several suppliers and transmission owners filed rate schedules with the FPC that provided for voluntary wheeling. Richmond Power & Light Company (Richmond) objected to these filings, claiming that they were unreasonable because they did not guarantee transmission access. The FPC refused to compel the utilities to wheel Richmond's power, stating that it did not have the authority to order a public utility to act as a common carrier.

The D.C. Circuit upheld the Commission. It acknowledged that Richmond's argument was persuasive in some respects, but stated that any conditions the Commission might impose could not contravene the FPA. The court examined the legislative history of the FPA and stated that "[i]f Congress had intended that utilities could inadvertently bootstrap themselves into common-carrier status by filing rates for voluntary service, it would not have bothered to reject mandatory wheeling * * *."[FN205]

However, the D.C. Circuit in no way indicated that the Commission was foreclosed from ordering transmission as a remedy for undue discrimination. Richmond also had argued that the alleged refusal of the American Electric Power Company (AEP) and its affiliate, Indiana & Michigan Electric Company (Indiana), to wheel Richmond's excess energy was unlawful discrimination because AEP and Indiana wheeled higher-priced electricity from other AEP affiliates. The court acknowledged that Richmond's claim of unlawful discrimination was theoretically valid, but found that Richmond had failed to prove its case. It noted that if Richmond had argued that the rates were unjustifiably discriminatory, or that Indiana's failure to use its transmission capability fully or to purchase less expensive electricity for wheeling resulted in unnecessarily high rates, a different case would be before the court.[FN206] The case thus does not in any way limit the Commission's authority to remedy undue discrimination.

In Central Iowa Power Cooperative v. FERC,[FN207] the FPC[FN208] reviewed the terms of the Mid-Continent Area Power Pool (MAPP) Agreement under its section 205 and 206 authority. The agreement contained two membership limitations. First, the agreement established two classes of membership, with one class being entitled to more privileges than the other. Second, the agreement excluded non-generating distribution systems from pool services. The FPC found the first limitation on membership —the two-class system—to be unduly discriminatory and not reasonably related to MAPP's objectives. The FPC conditioned approval of the agreement under section 206 on the removal of the unduly discriminatory provision. The FPC found that the second limitation, the exclusion of non-generating distribution systems, was not anticompetitive and did not render the agreement inconsistent with the public interest.

On appeal, the D.C. Circuit affirmed the FPC's decision. The court found that the FPC did have authority to order changes in the scope of the MAPP agreement, if the agreement was unjust, unreasonable, unduly discriminatory or preferential under section 206 of the FPA. The court stated:

The Commission had authority, * * * under section 206 of the Act, * * * to order changes in the limited scope of the Agreement, including the addition of pool services, if, in the absence of such modifications, the Agreement presented "any rule, regulation, practice or contract (that was) unjust, unreasonable, unduly discriminatory or preferential."[FN209]

However, the court agreed with the FPC's conclusion that the limited scope of MAPP was not unjust, unreasonable, or unduly discriminatory. The court recognized that a pool was not invalid under section 206 merely because a more comprehensive arrangement was possible.
The D.C. Circuit upheld the Commission's refusal to eliminate the second limitation on membership by ordering MAPP participants to wheel to non-generating electric systems.[FN210] However, neither the Commission nor the court was presented with the argument that wheeling was necessary as a remedy for undue discrimination.

***21562** In Florida Power & Light Company v. FERC (Florida),[FN211] the Commission ordered Florida Power & Light Company (FP&L) to file a tariff setting forth FP&L's policy relating to the availability of transmission service.[FN212] FP&L objected to including such a policy statement in its tariff and argued that the filing of such a policy would convert FP&L into a common carrier by obligating it to offer service to all customers.[FN213] There was no finding that the action ordered was necessary to remedy undue discrimination.

The Fifth Circuit Court of Appeals agreed with FP&L that the mandatory filing of the policy statement would require FP&L to provide transmission service beyond its voluntary commitment because such a requirement would change its duties and liabilities.[FN214] The Commission order would impose common carrier status on FP&L, the court found.[FN215] The court noted that the Commission did not rely on a finding of anticompetitive behavior and therefore the court did not address the Commission's power to remedy antitrust violations.[FN216]

The AGD court explicitly rejected the claim that the above line of cases establishes that the Commission lacks authority to require non-discriminatory open access.[FN217] Opponents of the Commission's order argued in AGD that Richmond and Florida, supra, stand for the proposition that the Commission cannot indirectly do what it allegedly cannot do directly, that is, impose common carriage. The AGD court rejected these arguments, stating that the petitioners read the electric cases far too broadly:

(n)either Richmond nor Florida comes anywhere near stating that the Commission is barred from imposing an open-access condition in all circumstances.[FN218]

The court noted that the Florida case had expressly left open the question of whether the Commission would be entitled to use an open access condition as a remedy for anticompetitive conduct, and that in Richmond the D.C. Circuit had said little more than that unwillingness to transmit for all could not be automatically deemed undue discrimination. The court also noted the Central Iowa case, supra, in which it had upheld a Commission order that found a power pooling agreement discriminatory on its face because the agreement gave one class of membership privileged status over another. The court stated that the Central Iowa case "upholds the power of the Commission to subject approval of a set of voluntary transactions to a condition that providers open up the class of permissible users."[FN219] The court added that it refused to "turn statutory construction upside down" by letting Congress' failure to grant a general power of common carriage prevail over the affirmative grant of the specific power to eradicate undue discrimination.[FN220]